ONTARIO POWER AUTHORITY

3

Supply Mix Background Reports

Volume 3 – December 2005

Ontario Power Authority

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Supply Mix Background Reports

Volume 3 – December 2005

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3.1 Overview of the Development of Power System Planning in Ontario

This section describes the historical evolution of power system planning in Ontario, in order to provide a context for the current planning exercise and its similarities and differences relative to planning exercises conducted in the past.

3.1.1 Key Findings

- Until the 1970s, power system planning was essentially an exercise to meet ever-increasing demand, with growth averaging 7% annually
- By the 1950s, Ontario's large waterpower sites were largely exhausted and alternate sources of generation, namely coal and nuclear power, had to be considered
- By the 1960s, the environmental and social issues of power system planning suggested that expansion of the power system would no longer be accepted simply as a public good
- By 1980, demand growth in Ontario had already slowed to 3.2% and demand management came to be considered as a component of electric power planning
- Ontario Hydro's 1989 Demand/Supply Plan was the only previous integrated power system planning exercise, but was withdrawn when economic circumstances changed
- Ontario's electricity industry was restructured under the Energy Competition Act, 1998, followed in 2002 by the opening of the market and its reliance on market forces rather than planning for new generation resources
- The partial curtailment of the market in late 2002 and the fact that only a limited amount of new generation capacity materialized, led to a renewed consideration of the need for supply planning
- The 2004 Electricity Conservation and Supply Task Force (ECSTF) concluded that the market approach alone would not produce the needed generation, and that Ontario needed a long-term planning function, a conservation champion, and a contracting function to serve as a credit-worthy counterparty to investors in new generation capacity
- The Ontario Power Authority was created as a feature of the Electricity Restructuring Act, 2004, in keeping with the ECSTF recommendations.

3.1.2 Introduction

The evolution of power system planning in Ontario has been characterized by adaptation to changing drivers, circumstances, and expectations of Ontarians.

In the industry's early period (early 1900s), which was dominated by improvements of the technology and the implications of this on economic growth, supply planning was the order of the day. By the early 1970s, a number of factors changed this simple formula. Firstly, growth of electricity demand began to recede in the 1970s. Secondly, economies of scale of new supply options diminished. Thirdly, inflation and high interest rates increased construction costs. All of these combined to make supply planning a riskier proposition. The result was the call for more formal and rigorous forecasting and planning methods. Sections 3.1.3 and 3.1.4 address planning during these two periods.

By the 1990s, in the midst of an integrated planning exercise, "demand-supply" planning came to an abrupt stop. In the face of significant excess capacity, combined with a serious recession, capital expenditures for both new demand and supply resources were judged unnecessary and imprudent. Demand management had the effect of raising rates. By reducing consumption there was a smaller total demand over which to spread Ontario Hydro's fixed costs, leading to upward pressure on rates. Subsequently, with its demand management programs discontinued, Ontario followed other jurisdictions into a new policy framework of competition and markets in 1998, with the expectation that market mechanisms would replace long-term supply development planning in securing needed generation. Section 3.1.5 expands on this phase of Ontario's development.

After significant legislative change in 2002 that limited the scope of the market, a new call for integrated planning of supply and managing demand resulted in the creation of the Ontario Power Authority. A description of this period is given in sections 3.1.7 and 3.1.8.

Section 3.1.9 completes the story on planning up to the Government's direction for the present planning exercise. Section 3.1.10 gives conclusions on the history of electricity planning in Ontario and on the distinguishing features of the present planning process.

3.1.3 Power System Planning Until the 1970s

Until the 1970s, the planning of Ontario's power system was generally a matter of negotiation within the electricity industry, between Ontario Hydro and the municipal electric utilities, and between the industry and the Provincial government. Public involvement, if any, was almost exclusively through the two industry interest groups, the Ontario Municipal Electric Association (representing utility commissioners on political and policy issues) and the Association of Municipal Electric Utilities (representing the utility managers on technical issues). In terms of meeting public expectations, the industry's sole task was to plan supply to meet the ever increasing demand resulting from expanded uses for electricity and economic growth.

Although not without its challenges, supply planning in Ontario's early development had proven to be very successful. Indeed, it worked so effectively that in meeting a supply crisis

during and after the Great War, Ontario Hydro (then known as the Hydro Electric Power Commission of Ontario) constructed the largest hydroelectric station in the world beginning in 1916 and completed in 1925 – Queenston-Chippawa (now Beck 1). The planning assumptions and affairs of Ontario Hydro were nevertheless sufficiently controversial that in 1922 the government appointed a royal commission of inquiry. When it reported in 1924, the Gregory Commission concluded that the operation of Ontario Hydro was "fundamentally sound".[1] With its experience of planning supply to meet growth, the wisdom developed in the industry that demand naturally increased by 7% per year.[2] The only period where growth did not occur was during the Great Depression.

Until the 1950s, the planning of Ontario Hydro's system was largely uncomplicated for two reasons. Firstly, the system was based on waterpower resources (hydroelectricity), which was then in abundance throughout Ontario. Secondly, while it had evolved to serve all of the settled parts of Ontario (save most notably for the Algoma, Cornwall, Gananoque and Fort Erie areas), Ontario Hydro in fact was made up of a number of smaller systems, such as the Niagara System, for ease of management.

New challenges arose by the 1950s from the exhaustion of all the large waterpower sites in southern Ontario and the constraints posed by a lack of ability to move power across the various systems. In order to address the first concern, alternate sources of generation had to be considered. The first step was to add thermal generation from coal-fired plants, with the addition of plants in Toronto (Hearn) and Windsor (Keith). Coal-fired generation was seen as the most economic choice for new supply. In addition, its operating characteristics enabled it to serve intermediate and peaking requirements.

The longer-term supplement to waterpower for base-load requirements was nuclear. Nuclear, despite its high capital costs and limited operating flexibility, was seen as suited to base-load operation by virtue of its low operating costs. It is at this point in the early post-war era that Ontario Hydro committed to work with Atomic Energy of Canada Limited to develop a commercial nuclear power program. By the early 1970s, Ontario Hydro had the Pickering A nuclear plant on stream and the Bruce A plant under construction. In 1973, additional plans were approved for B plants at both locations and a new station at Darlington soon afterwards.

To address the second concern of moving power across the province (there were a number of waterpower-based systems in Ontario, with the original Niagara System at 25 Hz and the rest at the new North American standard of 60 Hz) a consensus was formed for frequency standardization and transmission integration across systems at the new higher voltage of 230 kV. The rationale was that post-war economic development in Ontario required the development of one integrated power system.

[1] Gregory Commission, cited in Neil B. Freeman, *The Politics of Power: Ontario Hydro and its Government, 1906-95* (Toronto: University of Toronto Press, 1996), p. 55.
[2] Ontario [Porter Commission]. *The Report of the Royal Commission on Electric Power Planning: Volume 1, Concepts, Conclusions and Recommendations*, p. 27.

3.1.4 Power System Planning from 1970 to the Mid 1980s

Public concern with issues related to and raised by power system planning in Ontario first arose from the siting of a new series of 500 kV transmission lines around Toronto. They were required to accommodate the additions of power from the nuclear stations and the large fossil fuel fired stations, Nanticoke, on Lake Erie south of Hamilton, and Lennox, near Kingston on Lake Ontario. By that time, northeastern North America had experienced its first wide-scale blackout in 1965, and increasing attention was given to network security and supply reliability. In an earlier era, opposition from landowners or local governments to transmission (or generating stations) would have been viewed as standing in the way of the public good, but with the scale of these additions and the growth of rural non-farm residential living, the old consensus no longer held.

Faced with this predicament, the Ontario government appointed distinguished scientist, Dr. Omond Solandt, to a commission in 1972 to review the planning process used by Ontario Hydro. When it reported first in 1974 on the line from Nanticoke to Pickering and then in 1975 on the line from Lennox to Oshawa, the Solandt Commission made far reaching recommendations on the desired attributes and the expectations around public consultation for future Ontario Hydro studies. One of the recommendations was that Ontario Hydro should "investigate and recommend the routes that had the least disruption to the natural and social environment, taking into account cost and the preferences of the public." The Solandt Commission's findings were also instrumental in initiating Ontario's Environmental Assessment legislation.

Not long after Solandt had reported, in the face of the large-scale planned build up of the nuclear stations at Pickering, Bruce and Darlington, the Ontario government appointed the Royal Commission on Electric Power Planning in 1975 under the chairmanship of Dr. Arthur Porter, a professor of engineering at the University of Toronto. While Ontario had turned to nuclear power, in part for energy self-sufficiency, the coincidence of inflation and recession in the 1970s created significant concern in the public and legislature that demand would not materialize for the power. Indeed during the period 1975-79 when the Porter Commission was in session, growth had already slowed to 3.2%.[3]

The Porter Commission, which performed a detailed and exhaustive examination of the issues, reported in 1980. The most striking finding of the commission was that demand management must be included in electric power planning, rather than just supply planning. Along with other recommendations on conservation, renewables, nuclear power and alternative energy sources, its more influential recommendations on power system planning are the following:

[3] Porter Commission, op. cit., 27.

- **Recommendation 3.1** – Through the development of demand scenarios based on end-use data, future planning philosophy should increasingly be reoriented to demand management rather than maintaining the focus on supply expansion, as is traditional.
- **Recommendation 3.6** – For system planning purposes, Ontario Hydro should base its system expansion plan on a growth range for peak capacity to the year 2000 of 2.5 to 4% per annum.
- **Recommendation 11.11** – Ontario Hydro should be encouraged to continue, and where necessary, to expand its public participation program to ensure the public is fully involved.

3.1.5 Ontario Hydro's Demand/Supply Plan

In the first major planning exercise to follow the Porter Commission, Ontario Hydro published its Demand/Supply Plan Report, "Providing the Balance of Power", in late 1989. The plan recognized that annual growth had fluctuated between 3 and 7% over the three previous decades. With this backdrop, the demand/supply plan recommended a plan based on an average annual growth in peak demand of 2.2% over the 25 years to 2014, starting with 2.7% until 2000 and moving to lower levels thereafter.[4] This reduction was based on explicit recognition of drivers limiting growth and the demand management features of the plan.

In an exhaustive exercise, the Demand/Supply Plan Report contained an examination of 14 major portfolios of supply options, including additions from non-utility generators (NUGs) and purchases from Manitoba, before narrowing in on a proposed plan and two alternative candidate plans. With the planning assumption that generation capacity requirements would climb from 23,200 MW in 1989 to 39,800 MW in 2014, the preferred plan added nuclear for base load, coal-fired thermal with pollution abatement for intermediate load, and gas-fired thermal for peaking requirements. Of the two "acceptable" alternatives, one had more nuclear additions relative to fossil generation, and the other had more fossil generation.

By 1992, Ontario Hydro issued an "update" to the 25-year demand/supply plan to reflect the greater savings resulting from demand management, possibilities for refurbishment of existing facilities and increased reliance on NUGs. The Manitoba interconnection was to continue, but the addition of other new generation was to be pushed back further in the planning horizon.[5] While a number of factors had affected the plan, two stand out. Firstly, deep recession and the industrial restructuring effects of North American free trade reduced the forecast of future demand for electricity. Secondly, there was a growing recognition of the flexibility offered by developments in high efficiency gas-fired generation technology.

[4] Ontario Hydro, Demand/Supply Plan Report: *Providing the Balance of Power; Ontario Hydro's Plan to serve Customers' Electricity Needs* (Dec. 1989).
[5] Ontario Hydro, *Providing the Balance of Power: Update 1992*.

Ontario Hydro recognized that it was not likely to need approvals for major facilities in the 1990s and in 1992 it withdrew the plan from consideration. In part, this was due to the ever-broadening scope of the approval process as it proceeded and the fact that it was not at all clear that the approval process would come to a conclusion before the plan under consideration required revision due to the passage of time. And so would end Ontario's last full scale integrated planning initiative. Attention in Ontario Hydro instead turned to the restructuring of the electricity industry in Ontario under Maurice Strong, its new chair beginning in late 1992, and William Farlinger, its new chair beginning in late 1995.

3.1.6 Power System Planning from 1995 to 2002

With the experience of the serious economic downturn of the early 1990s coming shortly after the completion of the Darlington nuclear station, Ontario Hydro's high debt servicing costs and reduced revenues had become a major public policy issue.

An extraordinary portion of Ontario Hydro's revenue during the 1990s went towards interest payments on debt. In the face of its financial predicament, Ontario Hydro slashed operating and capital costs, largely by reducing staffing and eliminating most planned supply and transmission investments. Further still, Ontario Hydro itself developed and adopted a report entitled *Hydro 21*, recommending the electricity industry in Ontario be restructured.[6]

After the 1995 election, the new government appointed Donald S. Macdonald, the former federal Minister of Finance, as chair of an Advisory Committee on Competition in Ontario's Electricity System ("Macdonald Committee"). In its 1996 report, the Macdonald Committee recommended, generally, the elimination of Ontario Hydro's monopoly in generation and the introduction of a competitive electricity market.[7] The Macdonald Committee, whose recommendations did not explicitly address long-term planning, effectively set in motion the path for markets to in effect carry out supply and demand planning.

In acting on the recommendation of the Macdonald Committee, the government published a White Paper in 1997 entitled "Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario".[8] The main themes of the White Paper, which had not followed some Macdonald Committee recommendations on ownership and other matters, became the foundation for the *Energy Competition Act, 1998*. The key elements of the legislation included:

- Establishment of a marketplace for the simultaneous introduction of wholesale and retail competition (with the market opening subsequently set as May 1, 2002).

[6] Freeman, op. cit.
[7] Macdonald Committee, *A Framework for Competition*. May, 1996.
[8] Government of Ontario. *Direction for Change – Charting a Course for Competitive Electricity and Jobs in Ontario*. p. viii.

- Creation of the Independent Market Operator (now Independent Electricity System Operator, or IESO, out of the system operation function of Ontario Hydro) to manage the operation and reliability of Ontario's bulk power system and administer Ontario's new wholesale electricity market.
- Expansion of the mandate of the Ontario Energy Board, from the review of Ontario Hydro's bulk rates, to licence all market participants, regulate all monopoly participants and protect the interests of consumers.
- Separation and commercialization of the wires assets of Ontario Hydro into a regulated wires company (now Hydro One Networks Inc.) and the commercialization of municipal electric utilities to permit non-discriminatory access to monopoly wires business by all competitive market participants.
- Separation and commercialization of the generation assets of Ontario Hydro into a generation company (now Ontario Power Generation) that operates in conjunction with competing generators, and is subject to market power mitigation provisions.

While the new legislation was heralded in many circles for ending Ontario Hydro's monopoly, the legislative framework's reliance on markets meant that an integrated power system oversight within Ontario's newly restructured and competitive electricity industry was limited to assessment of adequacy and of interconnection proposals by market participants and assessment studies by the IMO. There was now a reliance on a market mechanisms to build the needed generation capacity.

3.1.7 Managing Supply through Competitive Markets – 2002 to 2004

Ontario's wholesale and retail electricity markets were opened in May 2002. Electricity prices rose soon afterwards to significantly higher and more volatile levels than consumers and the government had anticipated.[9] This was, in part, due to the combination of an unusually hot summer, growing demand, and the temporary unavailability of a number of Ontario's generating units. While the market could be said to have functioned properly by sending "supply scarcity" price signals, this point brought little comfort to consumers, who did not have the means to deal with volatility or to hedge risks adequately.

In the fall of 2002, the IMO's Market Surveillance Panel observed that the total available capacity in excess of summer peak demand for power had fallen from 19.2% in 1996 to -1.5% in 2002. With few new additions to supply for many years to meet increasing demand, the panel noted that Ontario had had to "rely on imports to balance supply and demand" every summer since 1998. The panel went on to conclude that:

[9] Michael J. Trebilcock and Roy Hrab. *What Will Keep The Lights on in Ontario: Responses to a Policy Short-Circuit*. C.D. Howe Institute Commentary. No. 191, December 2003, p. 5.

> [T]here is a serious shortage of generation capacity to meet Ontario's growing demand for electricity. If steps are not taken to address this situation, Ontario could face even more serious reliability problems next summer, leading to the possibility of supply interruptions and continued upward pressure on prices during periods of peak demand.[10]

In response to the rising prices and volatility experienced during the early months of Ontario's newly restructured and competitive electricity market, the government imposed a cap on retail electricity prices for a wide range of small and institutional end-users in November 2002. At the same time, rates for the distribution and transmission of electricity were frozen. The net result was a complete cessation of new investment in generation and significant cutbacks in new investment in transmission and distribution.

In June 2003, the government appointed the Electricity Conservation and Supply Task Force (ECSTF). In the face of the supply shortage, the ECSTF called for an "action plan for attracting new generation, promoting conservation and enhancing the reliability of the transmission grid."[11] The ECSTF, which included a wide range of industry stakeholders, submitted its recommendations in January 2004.

In its report to the Minister of Energy, the ECSTF observed that Ontario faced "a looming supply shortfall". This shortfall was attributed to the combination of growing demand for electricity, the gradual retirement of nuclear facilities, as well as to the phasing-out of coal-fired generation in the province. The ECSTF warned, first, that in 10 years Ontario would have only about half the generation capacity needed to ensure adequate and reliable supply and, by 2020, about two-thirds of the existing generation capacity would have reached the end of its planned operating life. With this backdrop, ECSTF concluded that "the market approach adopted in the late 1990s needs substantial enhancement if it is to deliver the new generation and conservation Ontario needs, within the timeframes we need them."[12]

During the work of the ECSTF, two significant events took place. Firstly, the Select Committee on Alternative Fuels, with all party agreement, recommended that the government replace coal-fired generating stations by 2015 for health reasons in its June 2002 report.[13] Secondly, a new Ontario government was elected in the fall of 2003. Setting a new course, it established electricity conservation targets for the province, including a 5 per cent reduction in Ontario's peak demand by 2007, and a 10% reduction in the government's own electricity consumption by 2010. The government also initiated a number of procurement processes for new clean and renewable generation resources for commercial operation within the next several years. And, in

[10] Independent Electricity Market Operator. *Market Surveillance Panel Report on the IMO-Administered Markets for the First Four Months: May – August 2002*. October 7, 2002. p. 131-32.
[11] Electricity Conservation and Supply Task Force. *Tough Choices: Addressing Ontario's Power Needs. Final Report to the Minister*. January, 2004. p. i.
[12] Ibid., p. i, 1, and 3.
[13] Ontario, *Select Committee on Alternative Fuels: Final Report* (June 2002).

2003, the government adopted the replacement of coal as government policy, but advanced the date to 2007. This date was subsequently changed to 2009.

In the context of the supply crunch that had been identified, the ECSTF proposed a number of key recommendations for addressing what it saw as a rapidly worsening situation. These recommendations included a more coordinated and integrated approach to establishing sector targets and guiding investment in both supply and demand-side resources. Key recommendations included:

- A long-term planning function be created to develop long-term forecasts and prepare integrated power system plans. These integrated power system plans would guide the development of Ontario's supply and demand resources to meet Ontario's electricity requirements.
- A conservation champion and coordinator be created to "serve as a focal point for a conservation culture in Ontario".
- A contracting function be created to serve as a credit-worthy counterparty and provide cost recovery certainty for investors in new capacity.
- Consumers should have access to a reliable default supply of electricity at stable prices that reflect the true cost of power.
- The government of Ontario should provide guidance on the desired resource mix for Ontario's electricity sector, including with respect to diversity of supply sources and environmental criteria.

3.1.8 Creation of the Ontario Power Authority – 2004

In June 2004, following release of the ECSTF recommendations, the government introduced new legislation whose objectives included increased conservation, ensuring price stability, and providing public leadership in the evolution of Ontario's electricity sector. A central component of the new *Electricity Restructuring Act, 2004*, which amended the *Electricity Act, 1998,* was the creation of the Ontario Power Authority (OPA). Its mandate is, generally, to address the deficiencies in the market, including long-term planning and conservation initiatives.

OPA, which is a statutory, not-for-profit corporation without share capital governed by an independent board of directors, reports to the legislature through the Minister of Energy and is licensed and regulated by the Ontario Energy Board (OEB). The responsibilities of OPA span four areas: Conservation Bureau; Power System Planning; Generation Development; and Electricity Sector Development.

Power System Planning: OPA's Power System Planning function involves the development and maintenance of a long-term (20-year) integrated power system plan (IPSP) for coordinating the supply, conservation and demand management, and transmission of electricity in Ontario. The IPSP, which must be approved by the OEB, must be developed every three years, or more

frequently if required by the Minister of Energy or OEB. It also must be designed to assist the achievement of the government of Ontario's goals related to, among other things, demand management and the adequacy and reliability of electricity supply, including electricity supply from alternative energy sources and renewable energy sources.

In developing the IPSP, OPA must follow any directives from the Minister of Energy on the goals to be achieved. These directives may relate to:

- the production of electricity from particular combinations of energy sources and generation technologies;
- increases in generation capacity from alternative energy sources, renewable energy sources or other energy sources;
- the phasing-out of coal-fired generation; and
- the development and implementation of conservation measures, programs and targets on a system-wide basis or in particular service areas.[14]

Conservation Bureau*:* The Conservation Bureau is housed within OPA and is directed by Ontario's Chief Energy Conservation Officer. The Conservation Bureau is responsible for providing leadership in the planning, coordination, and delivery of electricity conservation and demand management programs. The Chief Energy Conservation Officer is an executive member of OPA. The first annual report from the Conservation Bureau was released on November 7, 2005.

Generation Development*:* Until such time as a more sustainable marketplace takes hold in Ontario, OPA's Generation Development function is responsible for contracting for investment in new generation projects, conservation and demand management initiatives. Where OPA considers it advisable, it may enter into contracts for the procurement of electricity supply or capacity, conservation and demand management measures. This procurement must be made either in response to Minister's direction or in accordance with an OEB-approved procurement process.

The first large scale procurement effort was announced in late October 2005 for about 3,000 MW. Once an IPSP is in place, OPA may not commence the procurement unless it has, in consultation with interested parties, made an assessment of the capability of the IESO-administered markets or of other persons to meet the need for electricity supply or capacity, or deliver measures that will manage electricity demand.

Electricity Sector Development*:* OPA's Electricity Sector Development function is responsible for assuring smooth prices to residential and other designated customers, while recovering the full cost of electricity. This is done through the management of a variance account. The group is also responsible for leading OPA's work on designing options to help shift risk away from

[14] Electricity Act, 1998. s.25.30(2).

consumers to investors in the longer term as well as designing and implementing programs related to renewable energy and coordinating all of OPA's activities with respect to evolution of the electricity sector with related work being undertaken by the IESO.

3.1.9 Supply Mix Advice to the Minister of Energy – 2005

As OPA commenced work on preparing Ontario's first IPSP in the spring of 2005, the Minister of Energy requested "supply mix" advice by December 1, 2005 so that he may contemplate directives for the IPSP. In particular, OPA's advice is to include:

- Recommendations with respect to conservation targets for Ontario for 2015, 2020 and 2025, taking into account the target already set by the Government of Ontario for 2007;
- Recommendations with respect to additions of new renewable energy capacity by 2015, 2020 and 2025, taking into account the targets already set by the Government of Ontario for 2007 and 2010,
- Recommendations with respect to the appropriate mix of electricity supply sources to satisfy the remaining expected demand in Ontario, after conservation and renewable sources have been taken into account, and with particular attention to base-load, intermediate and peak availability of energy; and
- The phasing out of coal-fired generating facilities as a goal of the plan.

While OPA's task clearly includes considering conservation, renewable supply and conventional supply, the ordering is significant. OPA's role is to determine conventional supply needs only after first determining a plan for conservation and demand management and then a plan for renewable sources of supply.

3.1.10 Conclusion: The Rise, Fall and Reprise of Power System Planning in Ontario

The restructuring of Ontario's electricity sector in the mid-to-late 1990s saw the elimination of the integrated power system planning function that had played a central role in the development and management of Ontario's power system from 1906 to 1998. Shortly after Ontario's competitive electricity market was opened, Ontario faced a looming electricity supply shortfall. In the face of this supply challenge and inability, in the short-term, to rely on competitive markets, an administratively coordinated and integrated approach to establishing electricity sector targets and guiding investment was adopted.

OPA conducts independent planning for electricity generation, demand management, conservation, and transmission, and develops long-term integrated power system plans for Ontario. In this manner, OPA is a key component of the government's vision for a more

coordinated approach to establishing electricity resource mix targets and guiding investment in the province.

While the current round of planning will be based on similar technical and economic concepts to those of past planning exercises in Ontario and elsewhere, there are several distinguishing features:

- This round has the additional complexity associated with its being conducted in a "hybrid" regulatory environment for new resources - partly regulated and partly competitive
- There has been a very short development period which reflects the need for timely actions (Porter took five years, Balance of Power took over three years)
- The scope and level of detail was selected largely on the basis of what is needed for clarifying choices and decisions in the short term (three years)
- The 20-year time horizon of the plan is designed to provide context and uses scenarios to test the prudence and completeness of recommendations in the next 3 years. The plans are not intended as a rigid prescription, but rather as road maps to focus the near-term choices and highlight options for Ontario
- Regulatory review of IPSP is expected to be conducted by the OEB
- The IPSP will be updated every three years. It will adapt, learn from recent achievements and experiences and incorporate new insights, information and trends
- The scope of public participation, while compressed in time, is intended to be broad and comprehensive

3.2 Sustainability Principles and Integrated Planning

The purpose of this part is to outline the concepts of environmental sustainability aspects as they apply to electricity development as context for preparing the supply mix advice. To this end, this part will first review the environmental impacts from the various sources of electricity generation in their historical order of appearance in Ontario. This is followed by a discussion of sustainability concepts, with reference to their use in the supply mix advice. This is followed by discussion of the development of environmental assessment policy in Ontario as it relates to electricity generation, and then the methodology of the environmental analysis that has gone into the supply mix advice.

3.2.1 Key Findings

- OPA is committed to the pursuit of environmental sustainability in a fashion that preserves economically sustainability
- OPA supports the 1987 Bruntland Commission interpretation of sustainable development as that "which meets the needs of the present without compromising the ability of future generations to meet their own needs"
- As an initial step, OPA has analyzed each supply resource on the basis of its life-cycle environmental impacts, and put all resources on a common quantitative basis by developing "scored" formats, using weightings developed in the European Union.
- In developing its supply mix advice, OPA monetized carbon dioxide emissions and included these costs in its economic analysis of supply options
- OPA included considerations of environmental impacts beyond the end of the study period; i.e. beyond (2025) in an attempt to reflect considerations of inter-generational equity as well as intra-generational equity
- The precautionary principle, which is often invoked to "operationalize" the sustainability concept, counsels that proactive action to prevent harm is required where the potential for major harm exists, but can be difficult to apply when faced with trade-offs
- Until 2001, private sector energy facilities were not subject to environmental assessment (EA) requirements; the Electricity Projects Regulation (O.Reg.116/01) established private and public sector projects as equally subject to the EA process

3.2.2 Introduction

Awareness of the environmental consequences of human activity began to permeate popular consciousness more than 40 years ago with the publication of Rachel Carson's book, Silent Spring, which documented the effects of chemical pesticide use on bird populations. Since that

time, knowledge of and concern regarding increasing environmental degradation has risen steadily. In the 1970s, the Club of Rome argued that the then-current growth trends in world population, industrialization, pollution, food production and resource depletion would result in the world reaching its "limits to growth" within 100 years. Limits to Growth increased the prominence of sustainability issues for a significant segment of public opinion.[1]

Since the 1990s, there has been growing awareness of the link between human health and environmental degradation. Awareness of the profound complexity and interconnected nature of ecological, economic and social systems also grew throughout this decade. The concept of the "ecological footprint" was developed as a way of conceptualizing sustainability. A society's ecological footprint refers to the amount of land that is required to provide resources and absorb wastes resulting from human activity. The footprint is placed in the context of nature's ability to renew or regenerate itself, referred to as biocapacity. Current analysis indicates that humanity's footprint far exceeds the biocapacity of the earth, depicting an unsustainable situation.

3.2.3 Generation Development and Environmental Consequences

Hydroelectric

Ontario's early electricity system, from the beginning of the 20th century through the 1920s, was centred on waterpower generation facilities at Niagara Falls and other locations. Much activity during this phase was motivated by the prospect for provincial industrial development that arose from affordable electricity derived from a domestic resource.

There is currently debate within the environmental community as to whether large hydroelectric stations, such as the ones built during this period on the Niagara, Ottawa and St. Lawrence rivers, should be regarded as "sustainable" sources of energy. This debate may arise in the future in the context of sites in Manitoba and Labrador that are being considered as sources of long-term purchases for Ontario's needs.

Large waterpower installations raise concerns over serious effects on hydrological systems, affecting water flows and levels, sediment quality and quantity, and aquatic biology and habitat. Moreover, the creation of reservoirs can result in widespread flooding of land, negatively affecting local cultures and wildlife communities. At the same time, once constructed, the environmental impacts associated with the operation of hydroelectric facilities can be minimized with proper management, providing a renewable source of electricity with little waste and emissions. While many of these impacts also result from small-scale projects, they receive less attention because of their scale. This raises the question as to whether some of

[1] Donella H. Meadows et al. The Limits to Growth: A Report for the Club of Rome's Project on the Predicament of Mankind. Club of Rome. New York: Universe Books, 1972.

the newer generation technologies now seen to have small environmental footprints will be seen in the same light in future as they are deployed more frequently and on larger scales.

Coal-Fired Generation

Hydroelectricity remained the predominant form of electricity development in Ontario until the post-war period. In the 1950s, Ontario Hydro built the Keith coal-fired plant in Windsor and the Hearn coal-fired plant in Toronto. These were followed with Lakeview in Mississauga, Lambton near Sarnia, and Thunder Bay in the 1960s, Nanticoke in the 1970s, and Atikokan in the 1980s.

Coal-fired generation produces emissions that have significant environmental impacts. These emissions include oxides of nitrogen, sulphur dioxide, particulate matter, mercury, ground-level ozone and carbon dioxide. When released into the atmosphere, nitrogen oxides (NO_x) and sulphur dioxide (SO_x)transform into sulphuric and nitric acids which are the source of acid rain and associated devastation of water and soil systems. Ground-level ozone causes smog and pulmonary complications in humans.

Nitrogen oxides also cause smog and are much more potent greenhouse gases than carbon dioxide. Particulate matter consists of airborne particles that are small enough to remain suspended in air, and contribute to lung disease. Mercury is a toxic metal that can cause neurological, psychological and pulmonary disease, and has been associated with birth defects.

In addition to these emissions, coal-fired generation releases CO_2 into the atmosphere, contributing to global warming. Coal has the highest carbon content of any of the fossil fuels, resulting in the greatest CO_2 emissions per unit of energy produced. Coal-fired plants also create ash that may have to be put into landfill, with associated risks of leaching and soil and groundwater contamination.

Nuclear Power

During the 1960s through the 1980s, Ontario's nuclear program was established. It resulted in Ontario Hydro's construction of thousands of megawatts of power at the Pickering, Bruce and Darlington stations. Nuclear was seen as a domestic technology that used Canadian fuel, supplementing water for base load and removing the need to use coal for base load generation.

Environmental and safety concerns relate to radioactivity – from plant operations, the potential for reactor accidents, and the treatment of radioactive waste. Radioactivity consists of energetic atomic and subatomic particles and radiation. When radioactivity penetrates the human body, there is biological damage that can initiate cancers and cause genetic diseases in children. In practice, human exposure to radioactivity from nuclear plants is less compared to coal-fired

plants, and is lower than exposure arising from naturally-occurring radiation, commercial air travel or medical X-ray sessions.

The risk associated with reactor meltdown is small for Canadian technology as un-enriched uranium is used and system failure will cause the nuclear reaction to stop on its own. This is in contrast to other nuclear technologies that require intervention to stop the nuclear reaction in the event of failure. The issue of long-term storage of high level radioactive waste has begun to be addressed by the Nuclear Waste Management Organization in Canada.[2] It can take thousands of years for high-level radioactive waste to return to the level of radioactivity naturally present in uranium ore, and millions of years for the complete depletion of all radioactivity. Current proposals favour permanent storage of the waste deep underground, after several decades of storage at existing sites, with the potential for interim shallow underground storage at a centralized facility.

Recently, debate has arisen regarding the appropriateness of nuclear technology due to heightened concerns about global warming and the fact that nuclear power does not emit greenhouse gases. James Lovelock, a prominent environmentalist, has publicly stated that nuclear power will be necessary if the world is to avoid climatic catastrophe.[3]

Coal Deployment in the 1990s as Base-Load Power

Although coal-fired plants in Ontario were built for intermediate and peaking requirements, they filled the gap for base load power when the seven Ontario nuclear generators were taken out of service in the 1990s.

Ontario Hydro retrofitted its coal-fired stations with emission control technologies such as flue gas de-sulphurization and selective catalytic reduction. The decision came after there had been, during the 1980s and 1990s, increasing awareness of acid rain caused by NOx and SOx emitted by power plants.

While these technologies limit the emissions associated with acid rain, they do not limit the emissions of carbon dioxide associated with global warming.

New integrated gasification combined cycle (IGCC) technology provides the opportunity to separate out the carbon dioxide created by the electricity generation process. However, in order to prevent the release of CO_2 into the atmosphere, the CO_2 must then be stored (sequestered) somewhere, such as in depleted oil and gas wells or in deep saline aquifers. Ontario does not possess an abundance of these geological features, with the result that options for geological sequestration of carbon dioxide in Ontario are limited, though some options do exist.

[2] See Part 3.7 for a review of the recent report of the Nuclear Waste Management Organization.
[3] Lovelock, James. Nuclear Power Is The Only Green Solution, *The Independent*. May 25, 2004.

Natural Gas-Fired Generation

Construction of gas-fired plants in Ontario began in the 1990s, as generating facilities built by private sector developers ("Non-Utility Generators" or "NUGs") with contracts to sell their power to Ontario Hydro. With the opening of the electricity market in Ontario in 2002, the transmission grid was opened to private generators, stimulating some investors to build natural gas-fired plants. In 2004, the provincial government issued RFPs to address the impending supply shortage and the coal replacement policy, leading to the prospect of significant amounts of new gas-fired generation.

The environmental performance of natural gas-fired plants is superior to that of coal: on a life cycle basis, a combined cycle plant with an efficiency factor of 60% produces about one third of the greenhouse gas emissions of a pulverized coal plant operating with NOx and post-burner controls.

Renewables and Conservation and Demand Management

In the first years of the new century, increasing focus has been given to development of renewable technologies, particularly wind, and conservation and demand management (CDM). The cost of wind generation has fallen considerably over the past decades, and is now competitive with traditional forms of generation. In addition, the province has stressed the need to encourage a "conservation culture" and to recognize the true cost of generating electricity.

The deployment of smart meters to all Ontario customers is intended to alert consumers to the true cost of electricity, encouraging conservation and shifting consumption to off-peak periods. While load shifting does not result in a net difference in terms of energy consumed, it helps shave peak usage and alleviate the need to build new power plants to serve this peak demand.

The direct operational impacts of renewable technologies are minimal, however, wind, as an intermittent resource will usually require support from other generation sources, with associated environmental impacts. Moreover, there are some life-cycle impacts associated with the manufacture and transport of capital equipment, such as wind turbines and photovoltaic arrays. Despite widespread public support for renewable installations, they can nonetheless be difficult to site due to not-in-my-backyard ("NIMBY") concerns. Widespread general support for renewables does not always translate into local support for specific facilities.

3.2.4 Sustainability Concepts

Sustainable Development

The concept of sustainable development was popularized in 1987 by a report written by the World Commission on Environment and Development entitled "Our Common Future". The Commission defined sustainable development as that which "meets the needs of the present without compromising the ability of future generations to meet their own needs". The Commission elaborated on the environmental and social consequences of economic growth, and argued that sustainability required a balancing of economic, environmental, and social concerns.[4]

One of the key concepts of sustainable development addresses intra-generational and inter-generational equity. Intra-generational equity refers to the equitable allocation of resources and opportunity among the current generation. Inter-generational equity refers to the equitable allocation of resources and opportunity between generations. While discussions of intra-generational equity are often characterized by intense debate, questions of inter-generational equity can be even more difficult to resolve.

In its supply mix advice, OPA reflected both intra- and inter-generational equity. In addition to assessing environmental impacts together with economic factors for each year of the study period (intra-generational), this parallel treatment was extended to years beyond 2025 (inter-generational) by considering the "terminal" economic and environmental values.

One perspective on inter-generational equity holds that environmental degradation associated with economic growth today will result in the development of environmentally-benign technology tomorrow, enhancing the ability of future generations to meet their own needs. The alternative perspective holds that today's economic growth can be seen to compromise the quality of the environment faced by tomorrow's generation, unfairly shifting the costs of growth to the future while enjoying the benefits today.

Ultimately, these two perspectives differ on the degree to which the economy and the environment are regarded as substitutable for one another. A simple way of organizing the perspectives is to consider the appropriate degree of substitutability between economic growth and environmental protection. The perspectives can be put on a spectrum ranging from what is sometimes called "strong sustainability" to "weak sustainability". Advocates of "strong sustainability" would argue that increases in financial prosperity cannot compensate for environmental degradation.

[4] Worldwide Commission on Environment and Development, *Our Common Future*. New York: Oxford University Press, 1987.

Under "weak sustainability", human, natural and manufactured capital would be regarded as being substitutable for one another – as long as there is no overall decline in society's total stock of capital, sustainability can be regarded as having been achieved.[5] The "technological optimists" are on the far end of the "weak sustainability" spectrum, and regard the potential for growth as essentially infinite. Increased wealth and associated technological innovation are seen to be the means to overcome the obstacles imposed by physical environmental limits.

A full range of views exists between these poles. Some advocates highlight the complementarities rather than the tradeoffs between economic efficiency, environmental benefits, and social equity. Ideas such as natural capitalism and "factor four", promoted by advocates such as Amory and Hunter Lovins and Paul Hawken, call for increased materials and energy efficiency, which confer both economic and environmental benefits.

In its supply mix advice, OPA attempted to reflect the middle ground between the extremes of strong and weak sustainability, believing this to be compatible with the views of a majority of Ontarians. Decisions cannot be made solely on the basis of environmental considerations, yet one-to-one substitutability with economic considerations is likewise unacceptable.

Advocates of natural capitalism argue for a decoupling of economic growth from resource and energy consumption, sometimes called "dematerialization". This line of thinking is sometimes associated with calls for a decentralization of electricity systems. Proponents argue that electricity can be delivered more reliably, efficiently and with greater sustainability when it is generated close to where it is consumed, rather than in large centralized plants that may be significant distances from load centres.

Given these varying perspectives on sustainability, developing a working definition of the concept is a difficult exercise. Faced with this difficulty, the precautionary principle is often invoked to help "operationalize" the concept of sustainability. The complex nature of social, economic and ecosystems means they can be highly unpredictable, demonstrate irreversible changes, and be ambiguous in terms of chains of cause and effect. As a result of these characteristics, knowing with certainty whether specific courses of action will be safe or result in considerable harm can be difficult.

The precautionary principle counsels that where the potential for major harm exists, even if uncertain, then it is best to take proactive action to prevent such harm from occurring. It is generally considered that the application of the precautionary principle should be open, informed and participatory, including all potentially affected parties. Although it offers some guidance in decision-making, the precautionary principle can still be difficult to apply when faced with trade-offs.

[5] This is the Hartwick-Solow rule for inter-generational equity.

For instance, while the precautionary principle generally applies when considering potential environmental consequences, it can also be seen as relevant to other areas of social concern. As an example, OPA recognizes that it must exercise caution and prudence with respect to ensuring the adequacy and reliability of Ontario's electricity system. The potential for harm that could arise from an inadequate or unreliable electricity system is substantial. Caution must be exercised with respect to the environment, reliability and adequacy. Resolving tradeoffs that can arise among these important issues in terms of the precautionary principle is not straightforward.

In practice, policies aimed at promoting sustainability are often implemented with legislative and regulatory tools. These tools are commonly characterized as being either "command and control" or "market-oriented". Market-oriented approaches attempt to harness market forces to deliver environmental protection.

Market Mechanisms for Environmental Protection

Some observers argue that environmental degradation is a result of "market failure". A healthy environment is seen as a public good, which is inadequately valued by market forces. This line of thinking is illustrated in Garret Hardin's well-known essay, "The Tragedy of the Commons".[6]

Hardin uses the example of a common pasture where multiple farmers graze their livestock to illustrate that individual self-interest ultimately leads to overgrazing and the destruction of the commons. Coordination of all the farmers is required to prevent this destruction, because no farmer will limit grazing unless all farmers agree to do so.

One way to "coordinate" the grazing is to create many individually owned pastures, thereby creating property rights. Thinking in this vein sees air pollution as resulting from a lack of property rights. While it is not possible to own parcels of the atmosphere, a proxy property right can be created in the form of a permit or "right" to pollute. These permits can then be traded amongst polluters in a market. Since the act of pollution acquires a monetary cost, polluters will change their behaviour to produce the "optimal" amount of pollution. In theory, this would equal the level of pollution at which the associated environmental degradation is deemed as acceptable.

Compliance costs of all potential environmental impacts are included in the capital and operating cost estimate for the various supply options that were considered. Because greenhouse gas regulations are not in place yet, OPA in developing its supply mix advice included potential mitigation and compliances costs for carbon.

[6] Garret Hardin, "The Tragedy of the Commons," Garrett Hardin, *Science*, 162 (1968):1243-1248.

3.2.5 Environmental Assessment and Policy in Ontario

Continuing Evolution of Environmental Assessment in Ontario

The Ontario Environmental Assessment Act (EAA) was first enacted in 1975. The government of the day recognized that existing environmental protection legislation had not adequately provided for the comprehensive and coordinated consideration of environmental factors.[7]

A number of environmental reform initiatives have been undertaken since the EAA was first established in 1975. The Ontario Government created the Environmental Assessment Program Improvement Project (EAPIP) in 1988, which was followed by the creation of an EA Task Force in 1989. In the early 1990s, the Environmental Assessment Advisory Committee (EAAC) carried out public consultation on the task force's recommendations, and called for legislative and administrative changes to the province's environmental assessment program.

In 1993, the government adopted some of the EACC's recommended reforms. In 1996, the government undertook additional reforms to Ontario's environmental assessment regime.

In 2004, the government formed an advisory panel to recommend ways in which the province's EA process could be improved, particularly with respect to waste management facilities, transportation projects, and clean energy facilities. The report, submitted to the Minister of Environment in March 2005, contained 41 recommendations. It concluded that Ontario's Environmental Assessment Act is "fundamentally sound",[8] but that the implementation of the Panel's recommendations could deliver major improvements in the energy, waste and transportation sectors.

In general, the recommendations identified a need for clear and predictable principles, policies and procedures to guide the interpretation and application of the EAA, particularly regarding specific sectors and "green undertakings". Further, the report called for the establishment of sector-specific working groups to establish and clarify sector-specific EA policies and procedures.

The panel also proposed the establishment of a formal adjudicative process, administered by the Environmental Review Tribunal, for the review of bump-up and elevation requests. Greater cooperation among ministries and facilitation of common hearings were also recommended.

[7] Levy, Alan D., "A Review of Environmental Assessment in Ontario," *Journal of Environmental Law and Practice* 11:2 (June 2002), p. 195.
[8] Minister's Environmental Assessment Advisory Panel, Executive Group, *Improving Environmental Assessment in Ontario: a Framework for Reform*. Volume I, March 2005, p. 3.

Approvals and Permits Required For Electricity Projects

Any electricity project built in Ontario must obtain all approvals and permits required under the EAA, the Environmental Protection Act (EPA) and the Ontario Water Resources Act (OWRA). Environmental assessment approval and permitting processes are intended to provide for the protection, conservation and wise management of Ontario's environment.

Prior to 1998, Ontario Hydro undertook most electricity projects. As a public body, all Ontario Hydro projects were fully subject to the EAA, including the 1989 Demand/Supply Plan, "Providing the Balance of Power". The regulatory review process was not completed, however, after Ontario Hydro withdrew the plan in response to changed economic and other conditions. At this time, private sector energy facilities were not subject to EA requirements.

After the government opened the Ontario electricity sector to competition in 1998, changes to the EA requirements for electricity projects were required. In 2001, the Electricity Projects Regulation (O.Reg.116/01) was promulgated, establishing both private and public sector projects as equally subject to the EA process. The Electricity Projects Regulation identifies three classes of projects (Categories A, B, and C) which are subject to different levels of assessment, consultation and documentation requirements.
Category A projects are not subject to EAA requirements because of small size, fuel type or minimal environmental effects. For example, wind turbines smaller than 2 MW and natural gas generators smaller than 5 MW are not subject to EAA. Category B projects are subject to an Environmental Screening Process, and include wind turbines greater than or equal to 2 MW, hydroelectric facilities less than 200 MW, and natural gas generators greater than or equal to 5 MW. Projects are generally designated as Category B when the environmental effects are predictable and can be mitigated.

All projects that are subject to the Environmental Screening Process are required to conduct public consultation, with proper notification of stakeholders and identification and assessment of environmental and socio-economic effects of the project. Consultation must also address the concerns of adjacent property owners, interest groups and members of the public that may be directly affected by the project.

Where environmental effects are known to be significant (for example hydroelectric stations larger than 200 MW and 500 kV transmission lines longer than 2 kilometres), a project falls under Category C and is subject to an Individual EA.

In addition to requirements under the EAA, projects usually require approvals and/or permits under the EPA and OWRA. Under the EPA, Certificates of Approval can be required for projects that create noise or air emissions. Under the OWRA, permits and approvals may be required to remove water or for sewage impacts.

Recent Developments in Environmental Regulation and Policy

With the move to a hybrid electricity policy framework in 2004 and the creation of the OPA, a new regulation has been established that governs OPA's Integrated Power System Plan (IPSP). OPA is required by the Integrated System Plan Regulation, made under the Electricity Act, 2004 (O.Reg. 424/04), to ensure that economic and environmental sustainability and environmental protection are reflected in its long term system plan.

Concerns about air quality and global warming have led the government to its 2003 commitment to replace coal-fired generating plants in Ontario. As previously mentioned, the replacement policy actually had its origin in a unanimous recommendation of the Select Committee on Alternative Fuels in 2002. The government has also launched requests for proposals in order to contract for new renewable and clean generation and conservation and demand management. Additionally, the government has stated that 5 and 10 percent of Ontario's electricity supply will come from renewables in 2007 and 2010, respectively. The government has set provincial targets of a 5% reduction in peak electricity demand and a 10 per cent reduction of electricity use in government operations, by 2007.

Recently, the government has requested the OEB and OPA to work jointly on developing standard offer arrangements for renewable and clean generation in Ontario. These arrangements would offer a guaranteed price for electricity fed into the grid by small renewable and clean energy producers, and would help to alleviate some of the administrative and financial overhead associated with the RFP process that has tended to exclude the participation of smaller facilities.

At the federal level, the government released its plan for meeting Canada's Kyoto commitment, "Project Green", in early 2005. Canada has committed to reducing its greenhouse gas emissions to 6% below 1990 levels to 560 megatonnes (Mt) of carbon dioxide (CO_2). With projected business-as-usual emissions expected to be 830 Mt in 2010, Canada is considering measures to reduce emissions by 270 Mt in the 2008-2012 period.

Large Final Emitters (LFEs) are those companies emitting more than 8 kilo-tonnes of CO_2 per year, and are responsible for approximately 50% of Canada's total emissions. Fossil-fired (coal, oil, natural gas) electricity generators are considered LFEs along with firms in the oil and gas industry and certain mining and manufacturing facilities.

Under "Project Green", LFEs are required to reduce emissions by 45 Mt against the 2010 Business as Usual (BAU) projection. LFEs can meet this requirement by physically reducing emissions or purchasing emission offset credits. Firms that do not meet their physical emission limits will be able to purchase offset credits from facilities that have exceeded their emission reduction targets.

3.2.6 Supply Mix Methodology for Environmental Analysis

The OPA has reflected environmental impacts associated with electricity generation in its analysis. Prior to developing the methodology to be employed in its analysis, we reviewed approaches to addressing the environment in other jurisdictions. In general, a standardized approach to incorporating environmental concerns in the context of integrated electricity resource planning does not exist.

How jurisdictions address the environment differs greatly. Some address the impacts in a qualitative fashion, others focus on the potential impact of future carbon pricing, and still others do not address environmental consequences in any significant fashion.

The OPA has sought to learn from the experience and build on the strengths of other Integrated Resource Planning (IRP) exercises. In addition, we have sought to build on current practice by incorporating and combining approaches to environmental analysis in a way that does not appear to have been done in any other electricity resource planning exercise. As such, OPA has aimed to further integrate environmental and electricity planning.

Monetization and Indicator Approaches to Environmental Analysis

While there is a lack of standardization in the context of IRP, considerable work has been done in other fields in using monetization and indicator techniques for assessing different scenarios from an environmental perspective.

Monetization ascribes a price to negative environmental impacts, often in terms of dollars per tonne of pollutant. Where markets for trade in emissions permits have been created, such as for nitrogen oxides and sulphur dioxide in North America and carbon dioxide in Europe, the monetary value is usually taken as the market price. Where such markets have not been created, economists sometimes ascribe values to negative environmental effects using various techniques. Monetization as an approach, however, is problematic because it entails significant value judgments regarding the worth of environmental services, and cannot represent things that are priceless.

Indicator approaches to environmental evaluation can help to overcome some of the difficulties associated with monetization. These approaches measure key environmental drivers or effects in order to assess the current state of the environment and to monitor trends. Considerable development of environmental indicators has taken place at the national and global level, acknowledging that economic measures are inadequate representations of social well-being.

The Organization for Economic Development, the United Nations, and Canada's National Roundtable on the Environment and Economy have all developed indicator sets that measure key environmental variables associated with society as a whole. In the electricity sector, the

Pace Law School Energy Project, the Union of Concerned Scientists and other environmental non-government organizations developed the Power Scorecard, which is essentially an indicator approach for assessing the relative environmental performance of various generation technologies.

In addition to modeling, the cost of compliance with the July 16, 2005 Notice of Intent to Regulate Greenhouse Gas Emissions, OPA also ran a sensitivity analysis in which all carbon dioxide equivalent emissions were subject to mitigation costs of $15 per tonne.

Cost of Compliance with Federal Notice of Intent to Regulate GHGs

OPA's approach to incorporating the environmental impacts associated with Ontario's electricity system includes both monetization and indicator approaches. The analysis has incorporated a monetized price compliance with regulation governing all pollutants, and draft regulations on greenhouse gases as they apply to carbon for fossil-fuel based generation. The administrative structure and level of the price have been based on the Notice of Intent to Regulate Greenhouse Gas Emissions by Large Final Emitters posted in the July 16, 2005 Canada Gazette. The Notice proposes that non-fixed process emissions would be subject to a 15% reduction in emissions intensity relative to the 2010 Business-As-Usual forecast, and provides a $15 per tonne of carbon dioxide equivalent price assurance for the 2008 to 2012 period.

OPA's simulation has determined the amount of carbon dioxide emitted by fossil-fuel generators for each of the portfolios analyzed. For emissions that exceed those associated with a 15% reduction in emissions intensity against the 2010 Business As Usual forecast, a $15 per tonne CO_2 has been applied. If a fossil-fired facility reduces emissions beyond its emission reduction target, a credit of $15 per tonne CO_2 has been included in the analysis. The inclusion of a carbon price will impact the revenue requirement and risk associated with a given portfolio. A portfolio comprising of fossil-fuel generators that exceed their emissions reductions requirements will tend to have a higher revenue requirement and will be riskier on account of the uncertainty surrounding future carbon prices. We also explored future forms of regulation that may come into effect beyond 2012, the end date of the current regulation.

Incorporation of Life-Cycle Indicators

Since all environmental impacts cannot be captured through monetization mechanisms, OPA's supply mix advice is tracking several key variables in order to assess the relative environmental effects of the various portfolios under consideration. The indicators report the environmental impact associated with each portfolio, for instance the total emissions of sulpur dioxide or the total land use.

OPA has employed results of life cycle assessments in its analysis, meaning that the environmental impacts associated with all steps involved in generating a particular megawatt hour have been taken into account. The life cycle begins with resource extraction, moving through construction, operation, and ending with decommissioning.

The process of environmental assessment is very dependent on the characteristics of the specific site associated with a given facility, as the terrestrial, aquatic and species effects will vary depending on where a generator is located. As such, the indicators measured and reported in this analysis do not represent a detailed environmental assessment that is more appropriate at the project stage, but rather indicators of the environmental consequences of a particular portfolio based on the amount and types of generation that constitute it. By reporting these key indicators, portfolios can be compared on the basis of their relative environmental performance.

The indicators used in this analysis measure atmospheric, land, water and waste impacts as well as a resource availability indicator. Atmospheric impacts are represented by two indicators on the basis of emissions per megawatt hour: Contaminant Emissions and Greenhouse Gas (GHG) emissions. Oxides of nitrogen, sulphur dioxide, particulate matter and other hazardous air pollutants have been normalized on the basis of human health effects and aggregated into the single contaminant emissions indicator. Carbon dioxide, nitrous oxide, and methane have been normalized on the basis of global warming potential and combined into the (GHG) indicator. An indicator has also been included that accounts for radioactivity.

Land impacts are measured in terms of land use associated with a given portfolio, and reflect not only changes or loss of total land, but also negative impacts on the terrestrial habitat. Water impacts are represented by the water use associated with the portfolio, which is an average of water use and water withdrawal. The waste generation indicator considers extraction waste, operational waste, and decommissioning waste. Finally, a resource availability indicator identifies whether the fuel in use is renewable or not and takes into account the remaining years left of production for non-renewable resources.

These indicators have been individually reported in terms of absolute quantities in our analysis. In order to facilitate comparison, we have also scored the results based on their environmental impact. Scores for each indicator have been developed on a 0 – 10 scale, where 0 represents no environmental impact and 10 represents the worst performer. Results have been scored on each indicator – these individual scores have been added together to produce a total environmental score.

3.2.7 Conclusion

OPA's approach to including environmental analysis in integrated resource planning is comprehensive, and reflects the organization's commitment to the principles of environmental sustainability. Electricity development in Ontario has been associated with significant

environmental impacts, and various generating options today continue to have consequences for the quality of air, water, land, natural resource use and the production of waste.

Environmental regulation and policy in Ontario is established and continuously evolving in the interest of promoting sustainability, the public interest, and environmental protection. All electricity projects are subject to environmental regulation, which specifies requirements concerning the need for, and importance of, public consultation. In addition, the IPSP is required to reflect environmental sustainability and environmental protection. The supply mix advice represents a step on the path toward integrating environmental sustainability into the future evolution of Ontario's electricity system.

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3.3 Character of Ontario's Current Electricity System

The objective of this section is to provide an introductory-level description of the current electricity system in Ontario with respect to electricity and its usage, operation and planning considerations, supply characterstics and their need and evaluation, systems inter-connected with Ontario's system, the Ontario transmission system and system reliability planning parameters. This is essential context for all future plans.

3.3.1 Key Findings

- Energy demand is greater in the winter than in the summer, since winter heating and lighting more than compensate for summer air conditioning
- Peak demand is now greater in summer than in winter because of air conditioning load
- Peak demands in the summer are stressing the supply/demand balance to the point of load interruption, despite the addition of some generation to the supply
- Lack of energy storage in the power system means supply must be flexible and responsive enough to follow the deviations between forecast and actual load each day
- Ontario's interconnection capability amounts to between 3,150 MW and 4,050 MW
- Ontario and Manitoba have negotiated short-term supply from Manitoba to Ontario, and a longer-term possibility of about 1,300 MW is under consideration
- Purchases from Manitoba or Quebec/Labrador, and potentially from as far away as the Alberta tar-sands would involve major transmission enhancements and would be an important step in creating an inter-provincial grid

3.3.2 Introduction

This section is organized as follows:

- Concepts of electricity consumption. This includes hourly and seasonal patterns and forecasts of growth
- Operating and planning considerations, including supply characteristics and their need and evaluation
- The characteristics of base, intermediate and peak-load generation as well as reserve requirements for operating and planning
- Interconnected systems and imports of electricity, including Ontario's import and export capability, and the interconnecting situation in those provinces that potentially could be involved in purchases by Ontario
- Ontario's transmission system characteristics

- System reliability planning parameters, including the use of reliability standards, in particular those used in developing system reserve requirements.

A decade has passed since an overall system plan has been proposed for the supply of electricity to Ontario. In the interim, Hydro One Networks Inc. has continued to monitor and upgrade the transmission system, although only a few major upgrades to the bulk delivery system have been undertaken.

Through private sector development of new generation projects, some new gas-fired and some small hydro and wind generation resources have been built and are now operating to help meet the demand. The growth in energy has been modest, moderated by efficient new end-use technologies; however, peak demand growth has been rapid over the last 10 years, particularly during the summer. This has stressed the supply/demand balance to the point of load interruption.

Impending plant retirements, the policy to replace conventional coal-fired generation and growing summer air conditioning loads are just some of the factors driving the need for an integrated approach to power system planning. Important considerations for this exercise are energy and peak demand growth characteristics, classes of generation resources and their ability to meet the demand load, the nature of interconnected power systems and the makeup of the transmission system that takes electricity from generators to load centres. This section discusses these considerations.

3.3.3 Electricity Consumption: Usage Patterns and Forecast Growth

The power system has to cope with two aspects of the loads it supplies: power and energy. Power is the instantaneous demand presented by the simultaneous sum of the end users' loads, plus related transmission, transformation and distribution losses. It is expressed in terms of watts, kilowatts, megawatts. This is the demand that must be instantaneously supplied from the generators and transmission facilities that constitute the power system.

The other aspect of the supply needs is the energy requirement. Expressed in terms of watt-hours, (i.e., kilowatt-, megawatt-, gigawatt-, terawatt- or kWh, MWh, GWh and TWh), it is the product of the instantaneous demand and the time during which the demand is sustained.

Generators on the system convert energy from the primary energy sources (coal, nuclear, water, gas, etc.) into electrical energy.

The load may be broken down into three sectors, each having distinct usage characteristics:

Table 3.3.1 – Load by Sector

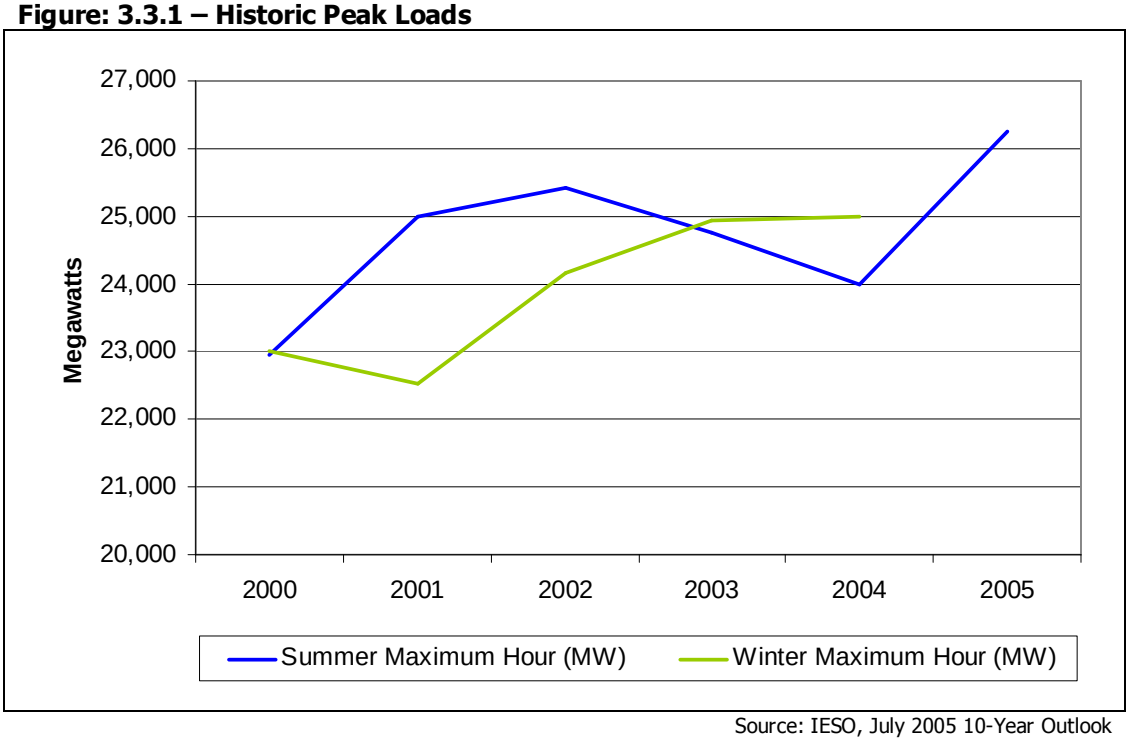
Type of Load	% of Total Load
Residential	30
Commercial	38
Industrial	31

Source: Statistics Canada, Report on Energy Supply – Demand in Canada, 1990–2003, Ottawa, Sept. 2004 (CANSIM)

3.3.3.1 Peak Demand Growth

Over the past several years load growth in Ontario has been substantial. The summer peak loads have been greatly affected by extremely hot weather. The highest demand recorded in Ontario occurred on July 13, 2005 and was 26,160 MW, compared to the forecast summer peak of 24,147 MW under normal conditions. This reflects two recent trends: summer demand growth has become very sensitive to weather, and summer peak loads have grown to be as big as or bigger than winter peak loads. Both of these effects are attributable to the addition of new residential air conditioning to the system load. The result is that Ontario's system is now classified as summer-peaking whereas it has been winter-peaking for all but the last half dozen years of its 100 year history.

Figure: 3.3.1 – Historic Peak Loads



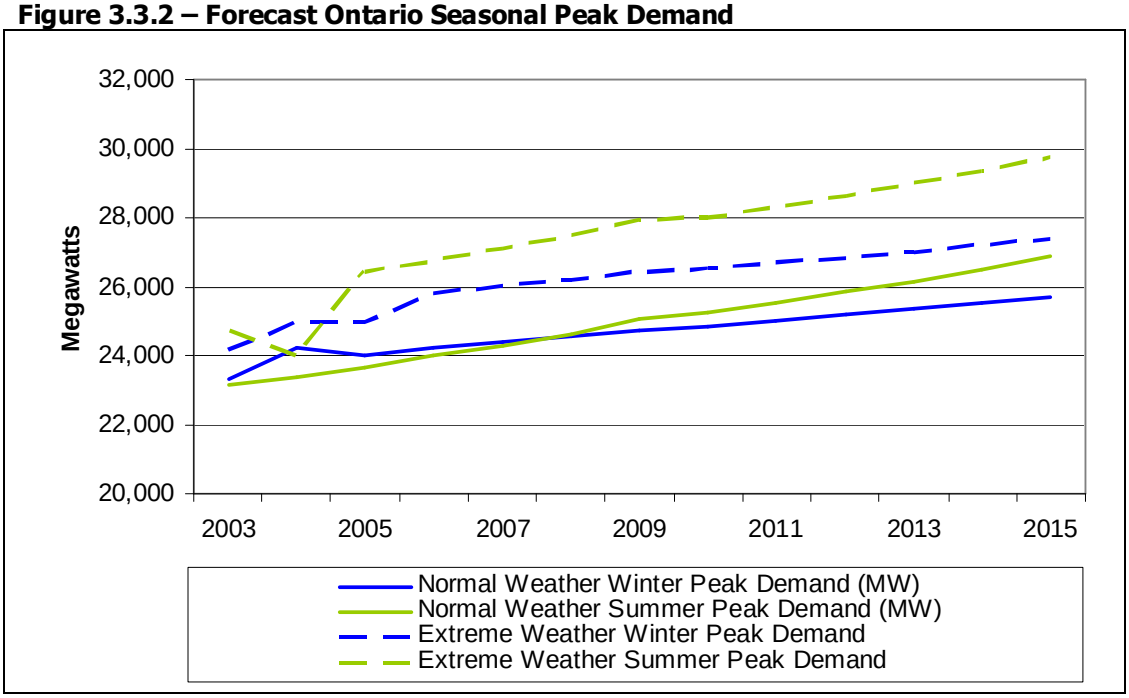
Source: IESO, July 2005 10-Year Outlook

Figure 3.3.1 show historical data for summer peaking in 2001 and 2002, with a reversal in 2003 and 2004, indicating that while the annual peak will generally occur in the summer, this can be

reversed by abnormal weather conditions such as a cool summer that leads to lower than normal air conditioning usage.

In 2005 the summer peak exceeded the 2004-5 winter peak again. This effect is reflected in the forecast seasonal peak demands shown in Figure 3.3.2:

Figure 3.3.2 – Forecast Ontario Seasonal Peak Demand



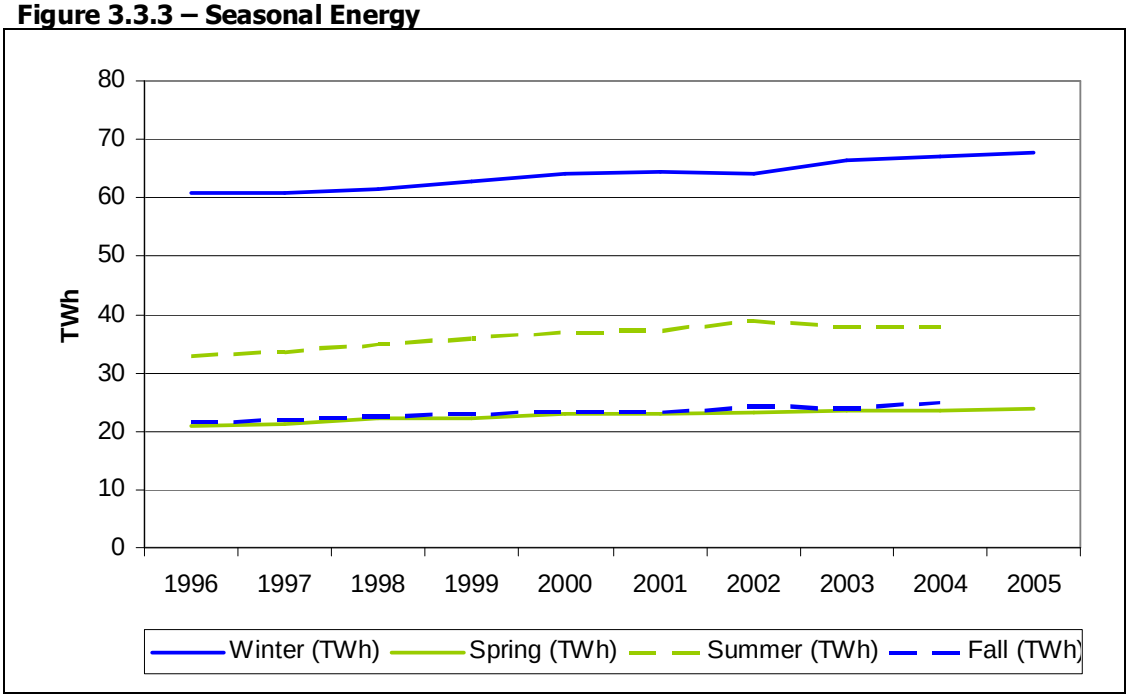
Source: IESO July 2005 10-Year Forecast

This information illustrates that the main objective in providing for the future peak supply for Ontario will be either to increase supply or increase demand management to reduce the demand, primarily in the summer.

3.3.3.2 Energy Growth

Energy consumption follows a different pattern, with the winter loads requiring more sustained delivery and therefore more energy than summer loads. During the spring and fall, the loads tend to drop to more modest levels as both heating and air conditioning loads are minimized. This creates a seasonal energy pattern as shown in Figure 3.3.3:

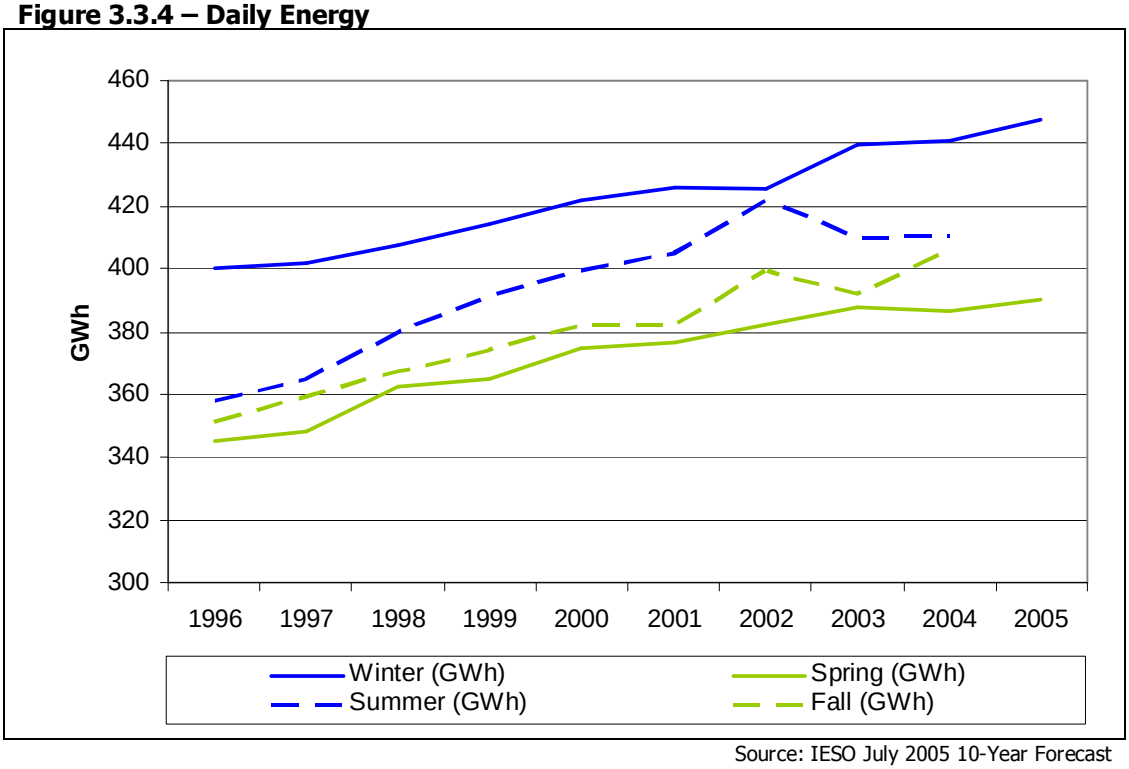
Figure 3.3.3 – Seasonal Energy



Source: IESO July, 2005 10-Year Forecast

This information can also be expressed as average daily energy, as shown in Figure 3.3.4.

Figure 3.3.4 – Daily Energy



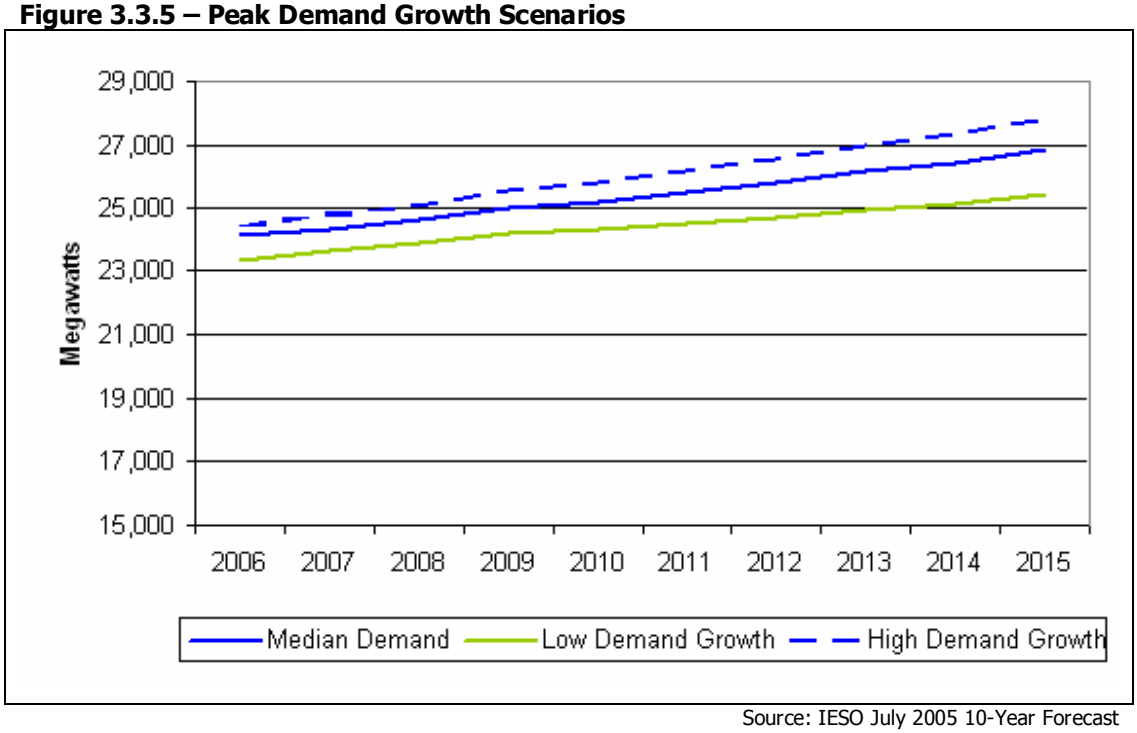
Source: IESO July 2005 10-Year Forecast

Electrical energy growth has been less than the growth rate of peak demand, primarily because of the nature of the air conditioning load, which demands power during hot spells but may be reduced or turned off in cooler periods. In terms of seasonality, the winter loads require more energy than the summer loads because of the more sustained demands of heating and lighting.

3.3.3.3 Uncertainty in the Demand for Electricity

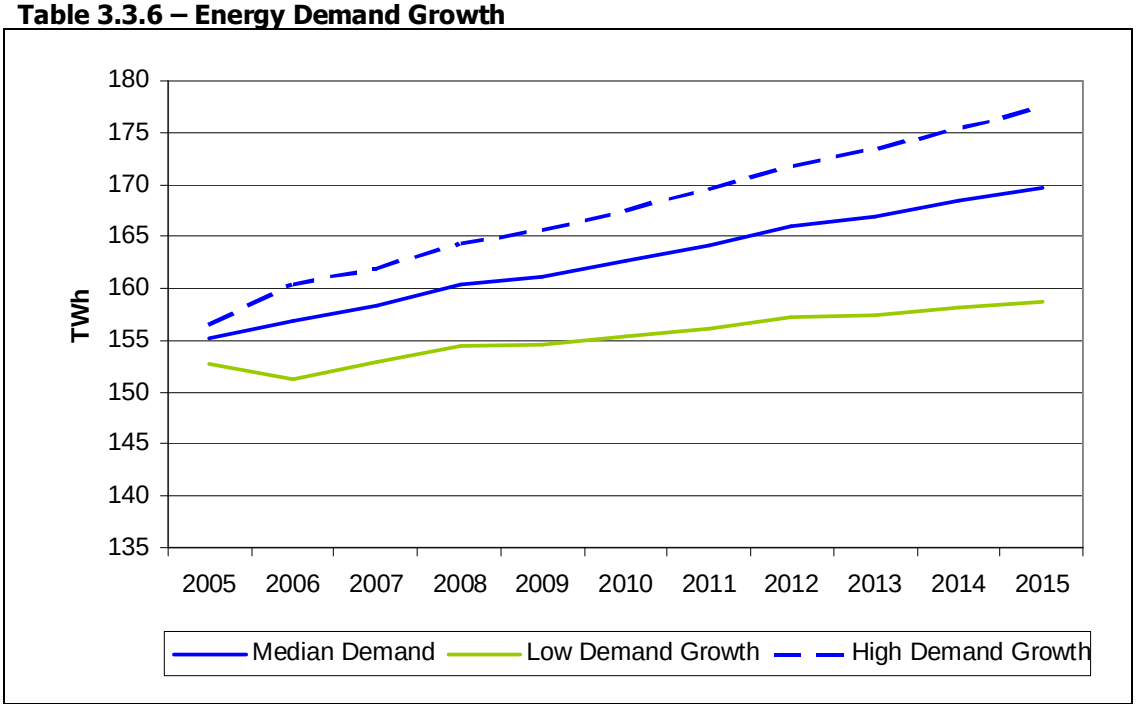
Load growth is driven by a number of factors: the economy and population are two of the largest and must be considered in planning for supply. There will be uncertainty associated with forecasts of population and economy. Accordingly, it has been the practice to consider Median Demand, Low Demand, and High Demand load growth cases in planning the power system. Figures 3.3.5 and 3.3.6 show the load scenarios included in the most recent IESO July 5, 2005 10-Year Forecast.

Figure 3.3.5 – Peak Demand Growth Scenarios



Source: IESO July 2005 10-Year Forecast

Table 3.3.6 – Energy Demand Growth

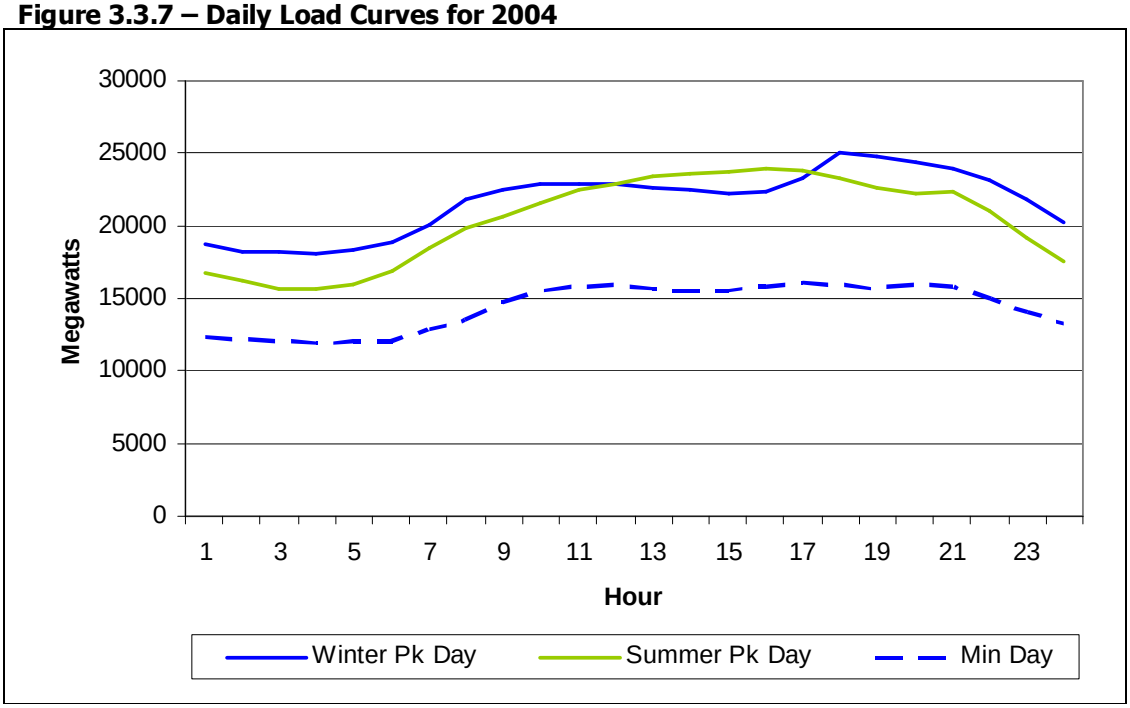


Source: IESO July2005 10-Year Forecast

3.3.3.4 Daily Load Shape

Another aspect of the load, which must be considered in designing a mix of supply facilities, is the daily load shape. Depending on the day of the week or the season, the load is typically at its lowest between midnight and 6:00 am, rises in the morning, peaks in the late afternoon to evening, decreases in the late evening and levels off again around midnight. The morning increase in load coincides with commencing industrial, business and institutional operations, breakfast time, showering and other activities that use electricity. In the winter, load levels off or even decreases slightly through the afternoon and peaks again around supper time with the use of appliances and lighting. In the summer, air conditioning loads and longer days lead to more sustained, longer peaks. Figure 3.3.7 illustrates typical daily load curves for a winter and summer peak day. The minimum daily load curve illustrated is more typical of a spring or summer normal weather day or on a weekend when industrial, commercial and residential activities are not placing as much load on the system.

Figure 3.3.7 – Daily Load Curves for 2004



Source: IESO Market Data

3.3.3.5 Electric Reliability

One of the most noteworthy things about the loads in Ontario is the public expectation, if not demand, that the supply of electricity be reliable. Moreover, the Ontario Market Rules specify this as a requirement and it is also a requirement of standards set by the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), in both of which Ontario is an active participant. This factor has become so engrained in our daily life that most Ontarians and Ontario businesses would have difficulty getting along without power for long, as demonstrated during the blackout in 2003.

Commercial and retail businesses come to an almost absolute standstill in the absence of power as a result of the highly computerized equipment used universally now. Most commercial buildings become very uncomfortable, if not uninhabitable, in a short time without air conditioning and lighting. Modern industry is heavily dependent on power both to drive production machines and to control the processes that manage the machines.

Farmers, particularly those with certain poultry and livestock operations, need electricity to maintain acceptable environments for their produce and for such functions as milking and product refrigeration.

Our climate makes reliable supply of power important to everyone in terms of keeping people warm and comfortable in the winter, as well as helping with security and safety. Few household

heating systems operate without power, no matter what the primary fuel, and a few hours outage on a cold day is enough to cause anxiety to most people.

A reliable power supply is important to the future welfare of the provincial economy. Many large corporations base their decisions about future expansion on studies of possible alternative locations, on a global basis. It is known that the projected reliability and costs of power supplies in possible areas of expansion are major factors in such decisions.

3.3.4 Operating and Planning Considerations

The primary role of generation is to meet the power demands of the load. This must be done instantaneously because there is no energy storage of any meaningful amount in the electric power system. Electricity is the ultimate "just in time" product where production and use must be exactly matched on a moment by moment basis.

In addition, almost all of North America is synchronously interconnected into a very large 60 Hz system, with every motor and generator rotating at a speed directly related to the 60 Hz frequency. (Québec and Texas are both interconnected to their neighbours via High Voltage DC which frees them from being in synchronism with the rest of North America, but their internal systems also operates at 60 Hz. The eastern and western halves of North America are also separated, which in Canada is at the Alberta-Saskatchewan border where there is also a High Voltage DC interconnection.)

Out of these two principal facts, it follows that:

- Total generation must meet total load (including losses) on an instant-by-instant basis.
- When the load increases rapidly in the morning, the connected generation must be able to increase output, or ramp-up, to meet the demand. The result is that an appreciable portion of the total generation fleet must be able to adjust output rapidly, which is a significant parameter in system and generation design.
- During sudden changes in demand, such as during a hockey game when an intermission means sudden opening of refrigerator doors and other intermission activity, generation must be able to change to manage the sudden increases and subsequent decreases instantly.
- Since half a continent is interconnected with transmission ties that have delivery limits, each utility and utility area has obligations to hold up its part of the load, more or less independently of others.

Not only is reliability important to consumers of electricity, it is also important to owners of transmission and generation facilities. Very small decreases (or increases) in system frequency

from 60 Hz (a few Hz[1]) could cause serious damage to rotating generators, both large and small. Normally these are protected from frequency variations by equipment that automatically disconnects them under such conditions. Similar considerations apply to transmission facilities – if they become overloaded, they have automatic protection that removes them from operation. Moreover, once automatic disconnection occurs, additional stress is placed on the system elements remaining in operation, leading to increased risk of cascading disturbances and potential blackouts. It is therefore essential to design and operate a system conservatively, for example to control system frequency to within a very small fraction of 1 Hz.

3.3.4.1 Supply Characteristics, Need and Evaluations

Broadly speaking, generation is broken up into three categories:

- Base-load generation (nuclear, run of the river hydroelectric, cogeneration)
- Intermediate-load generation (coal, oil, combined-cycle generation)
- Peaking generation (gas turbine, peaking hydroelectric, pumped storage generation)
- As available generation (wind and solar)

Base-Load Generation: These are facilities that have low operating costs or physical characteristics such that they cannot change output rapidly without significant risk of damage. Such damage may arise from rapidly changing temperature and pressure in their turbines as output changes.
Intermediate-Load Generation: These tend to be units with characteristics not entirely unlike base-load generators, but which have higher operating costs (large coal and oil-fired units or gas-fired steam generators) and with physical characteristics more tolerant of loading variations. Some of these have been used in Ontario for years to follow load on a limited basis and they form a significant part of the job of ramping up in the morning to meet the load.

Peaking Generation: These tend to have either high operating costs or significant primary energy storage (headponds in hydroelectric plants). They can usually change output rapidly (gas turbines can be started and loaded in minutes normally) and peaking hydroelectric plants can be operated to provide almost instantaneous response to changes in demand.

It should be noted that while gas turbines have relatively low capital costs and short construction lead times, peaking hydroelectric stations usually have high capital costs because of the dam infrastructure required to contain and manage the headpond that provides the energy storage. Much peaking capacity has historically been provided by older base-load plants that have become relatively more expensive to operate compared to newer larger base-load

[1] Hz is Hertz, the unit of frequency – the number of cycles per second of the alternating voltage and current.

plants. In peaking service, such base-load plants will age prematurely and become less reliable but still make an important and economically sound contribution to the overall supply portfolio.

Although all three are required to constitute a reliable power system, the intermediate and peaking generation are critical to maintaining moment-to-moment regulation of the power system and reliability. Sufficient amounts of base load generation are important to maintain low energy costs.

"**As Available" Generation**: Wind, solar, and some small hydroelectric generation provide power when and if certain natural events occur, which gives them a somewhat unpredictable output. Although the environmental benefits and low incremental costs of these sources of generation are significant, in terms of system operations they may pose addional challenges depending upon the characteristics of their output. If output goes down during the morning ramp up, it requires additional generation to ramp up faster, a requirement that can add costs.

Operating and Planning Reserve Requirements: In operating the system, it is necessary to allow for some of the generators to be out of service at any time. The amount to be allowed for is determined by using probability analysis, with a level of about 18% in Ontario. (This amount also covers some uncertainty in the weather effects on the load). This means that the total generation required to be available to operate is about 118% of the firm connected load plus losses. Firm connected load is the total provincial load minus those loads that are contracted to be interruptible when required by the system operator.

Interruptible loads, by virtue of being able to be disconnected on short notice, reduce the reserve margin from what it would otherwise be. On a system such as Ontario's, with mixed large generation and smaller generators, the average amount of generation forced (unexpectedly) from service might be about 9% - essentially the size of the largest single generator operating.

The balance of the 18% margin is to allow generators to be taken out of service periodically for repairs, inspection and maintenance. However, maintenance outages, unlike forced outages, can be managed – they are usually scheduled into the lighter load periods in the spring and fall, minimizing the costs and reliability impacts of having generation out at times of peak loads.

In planning for future supply, slightly higher reserve levels are required to allow for the uncertainties of load and generation in the more distant future. This is also included in the 18% margin which is the level used in developing the supply mix advice.

Evaluating Alternative Generation Sources. Evaluations must take account of the four main stages in the life cycle of a generating plant:

- **Development Stage**: is the stage when capital is spent buying the components, building the

plant and building the transmission required to incorporate the plant into the power system. Since there is little if any energy produced during this stage, there are no offsetting revenues from sales of power and energy. Some generation types have major capital expenses (nuclear, large fossil plants, most peaking hydroelectric plants with large dams). These normally require up to 10 years for development. Gas turbine generators can be put into operation typically after only 2 years and development costs are much lower.

- **Operation Stage**: is the stage when the majority of costs are related to the incremental cost of producing energy (fuel, ash disposal, nuclear waste disposal, water rentals, operating costs such as operators, maintenance, etc). In this stage the lower energy production costs of some alternatives justify the higher capital costs associated with their development. It is worth noting that the nuclear generation alternative has some fixed unavoidable ongoing costs, for security and safety management. There may also be periodic or continuing capital modifications required to keep the plant in operation.

- **Rehabilitation Stage:** is the stage when the generation has reached the end of its useful life for any number of reasons such as technological obsolescence, safety or efficiency. At this point, depending upon the type of plant, the need for generation, the desirability of the site, and other factors, the plant may undergo major rehabilitation or reconstruction. The costs associated with rehabilitation will depend on the type of unit and its physical conductors.

- **Decommissioning Stage:** is the stage when the plant is brought to an acceptable end of life situation. The associated costs are part of its life-cycle costs and need to be considered in evaluating the alternatives. Nuclear plants require a long "cool-down" period for radioactive components and eventual dismantling and safe storage. Spent fuel must be removed and safely managed. Other generation types also have retirement costs of some amount, depending on the individual plants.

The challenge is to find a way to add up costs and benefits that occur in different time periods in a way that allows a fair, "apples-to-apples", comparison among the alternatives. This is done by comparing the Levelized Unit Energy Cost (LUEC), a measure that considers all costs incurred over the life of the plant. It involves using the net present value (NPV) method. The NPV method takes the total costs incurred in each year of the plant's life, discounted to the present year using financial discounting methods, and sums the values over the life of the plant to find the total NPV of the plant. As described in parts 2.6 and 4.1, the LUEC analysis was used extensively in developing the supply mix advice.

LUEC analysis allows one to take into account both the initial capital costs of an alternative and the subsequent operating and retirement costs, in a fair way. The LUEC is a good indicator of economic cost, but is not the only factor in the final decision. As described in parts 2.6 and 4.1, LUEC analysis must be combined with portfolio analysis when the supply decision must result in a mix of different supply alternatives. Portfolio analysis also involves the NPV method. Beyond the economic analysis of LUECs and portfolios, factors such as environmental impacts

for incorporating transmission requirements and risk management and system operability considerations must also be taken into account.

3.3.5 Interconnected Systems and Imported Power and Energy

3.3.5.1 Overview

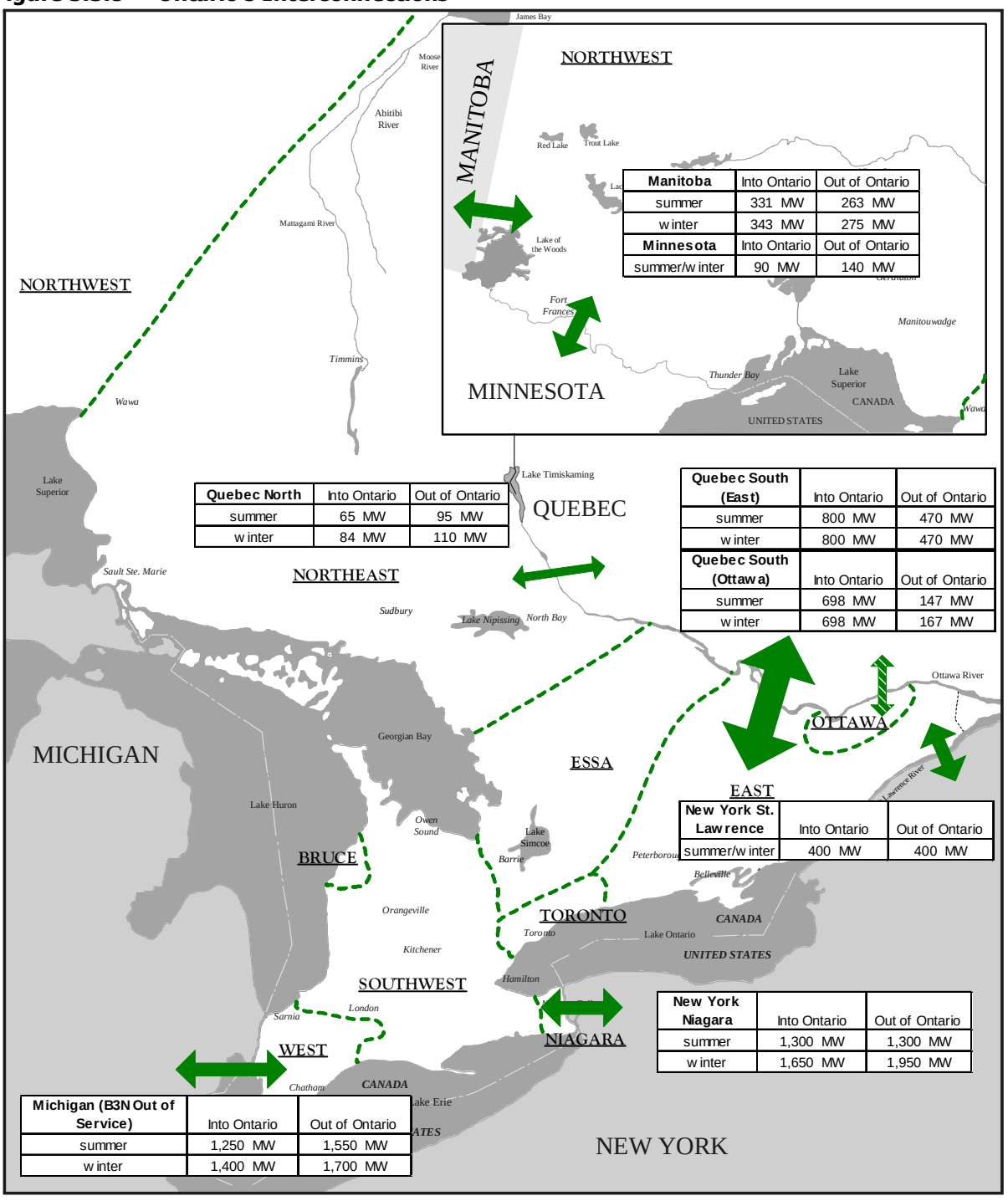
The Ontario power system is connected directly to the power systems of Manitoba, Minnesota, Michigan, New York and Quebec, and they, in turn, have interconnections with the utility systems adjacent to them. Lower interconnection costs and larger benefits from sales to the U.S. have meant that interconnections between Canadian provinces and the U.S. tend to be much stronger than those between neighbouring provinces.

Ties between Quebec and other jurisdictions, including Ontario, are unique in that, because it is a "low inertia" 100% hydroelectric system, the Quebec system does not need to maintain frequency as precisely as its surrounding systems and it can save significant costs by not doing so. This does require however, that the Quebec system be connected "asynchronously" with its neighbours who do control frequency more precisely. The connections are made through High Voltage Direct Current (HVDC) facilities which exist with all its neighbours except Ontario at present.

Exchanges of power between Quebec and Ontario require isolation of load or generation of one system onto the other, a sometimes difficult and lengthy process that seriously inhibits both the amount and speed of emergency assistance between the provinces. A new 1,250 MW HVDC interconnection with Quebec in the Ottawa area was planned a few years ago, but did not materialize. A new effort at completing this tie is now underway.

The map in Figure 3.3.8 shows the locations and individual ratings of Ontario's interconnections.

Figure 3.3.8 – Ontario's Interconnections



Manitoba	Into Ontario	Out of Ontario
summer	331 MW	263 MW
winter	343 MW	275 MW
Minnesota	Into Ontario	Out of Ontario
summer/winter	90 MW	140 MW

Quebec North	Into Ontario	Out of Ontario
summer	65 MW	95 MW
winter	84 MW	110 MW

Quebec South (East)	Into Ontario	Out of Ontario
summer	800 MW	470 MW
winter	800 MW	470 MW
Quebec South (Ottawa)	Into Ontario	Out of Ontario
summer	698 MW	147 MW
winter	698 MW	167 MW

New York St. Lawrence	Into Ontario	Out of Ontario
summer/winter	400 MW	400 MW

New York Niagara	Into Ontario	Out of Ontario
summer	1,300 MW	1,300 MW
winter	1,650 MW	1,950 MW

Michigan (B3N Out of Service)	Into Ontario	Out of Ontario
summer	1,250 MW	1,550 MW
winter	1,400 MW	1,700 MW

Source: IESO July 2005 10 Year Forecast

The import/export capability available at any moment in time ("coincident capability") is not necessarily the arithmetic sum of the individual flow limits shown on the preceding map. These coincident capabilities are shown below.

Table 3.3.2 – Coincident Interconnection Capability

Export Capability		Import Capability	
Now	After Modifications to Interconnection Facilities	Now	After Modifications to Interconnection Facilities
Summer: 2,337 MW to 5,537 MW	4,037 MW to 5,537 MW	Summer: 2,995 MW to 5,295 MW	3,995 MW to 5,295 MW.
Winter: 2,684 MW to 5,884 MW	4,484 MW to 5,884 MW	Winter: 3,526 MW to 5526 MW	4,726 MW to 5,526 MW

Source: IESO July 2005 10-Year Forecast

In fact, the level of assistance available to Ontario is less than the coincident capabilities stated above. Studies conducted in 2004 suggested that the level of assistance available to Ontario from the present interconnections at the time ranged between 3,150 MW and 4,050 MW. This capability can either increase or decrease, depending upon such factors as generation, load and transmission developments in Ontario and in neighbouring, interconnected systems.

3.3.5.2 Ontario's Interconnected Neighbours

The characteristics of each of Ontario's interconnected neighbours are as follows:[2]

Manitoba

Manitoba is served by Manitoba Hydro. The dominant supply is hydroelectric (98%), much of it in the far northern part of the province. Manitoba also has a small coal-fired plant at Brandon and four natural gas-fired thermal units and is beginning to utilize wind-power. The company estimates that only about one half of its potential hydro resources have been developed. Manitoba is in the early stages of negotiating with Ontario for a sale of power from a proposed new 1,300 MW hydroelectric generating station at Conawapa on the Nelson River.

Manitoba Hydro had its highest peak load in winter 2004-2005 at 4,146 MW and, according to its 2005 annual report, has a system capability of 5,470 MW. The province has good interconnections with the U.S. in Minnesota and North Dakota and uses them both for energy sales and for diversity exchanges in which the power sold during the summer to the U.S. can be recalled to help in meeting Manitoba's winter-peaking loads. It also has ties with Saskatchewan.

[2] The information was derived from a number of sources. The main source was the National Energy Board Outlook for Electricity Markets 2005-2005. This was supplemented by current information from the utility annual reports, government data reports and other analyses for the Churchill River Developments in Labrador.

Quebec

Quebec, with some minor exceptions, is served by Hydro-Québec, a Crown Corporation wholly owned by the Government of Quebec. It is the largest electricity market in Canada and the country's largest exporter. The dominant supply is hydroelectric (93%), most of it remote from the Montreal area load centre and a substantial part of it purchased from generation in Labrador at Churchill Falls on the Churchill River (about 5,000 MW).

Hydro-Québec's recent annual report indicates a 2004-2005 winter peak load of about 34,000 MW and a planned supply of about 38,000 MW. A long moratorium on new generation, combined with strong load growth, has resulted in a tight load supply situation and reduced export sales in recent years. Hydro-Québec now has an aggressive expansion program underway and should soon be in a better situation.

Hydro-Québec generation is characterized by huge primary energy storage in the form of very large reservoirs at many of its plants. These conditions provide it with the ability to supply its loads even during drought periods and make sales to neighbouring markets with relatively low risk.

Hydro-Québec has some oil-fired generation (600 MW Tracy GS) and some gas-fired generation, but they make up a small part of its supply and their use is avoided when possible. Hydro-Québec also owns a 675 MW CANDU generator (Gentilly-2), has some wind projects and has HVDC interconnections with New York, New England and New Brunswick and strong ties to the generation in Labrador.

Saskatchewan

Saskatchewan is served by SaskPower Corporation, a crown agency. SaskPower reports an installed generation base of 3,000 MW plus about 500 MW of purchases, and a winter peak load of about 3,000 MW. About half of the generation is coal-fired (lignite) and the balance of the generation is gas and hydroelectric, with about 10 MW of wind powered generation. SaskPower has a program of adding new low environmental impact power, including wind, low-impact hydro, biomass, solar, flare gas, and heat recovery generation. It is also developing 150 MW of wind power in southwest Saskatchewan. Saskatchewan has a 230 kV interconnection to the U.S., a back-to-back HVDC tie with Alberta and three 230 kV ties to Manitoba.

Alberta

Alberta has about 12,090 MW of supply and about 10,000 MW of peak demand. In addition, it has a 500 kV and two 138 kV ties to BC with a total capacity of 1,000 MW. These ties are used to exchange energy with either BC or the U.S. northwest. Alberta also has a 150 MW interconnection with Saskatchewan. Coal provides 48% of the required capacity, natural gas

about 41%, and the remainder is hydroelectric, wind and other renewables. A major user of electricity is the growing oil-sands operation in northern Alberta. Most of the recent increases in generation in Alberta have been natural gas-fired. The provincial government's voluntary renewable supply requirement is targeted to achieve an additional 3.5% of energy from renewable and alternative energy by 2008.

New Brunswick

New Brunswick has about 3,800 MW of installed generation and about 3,340 MW of winter peak demand. It has 15 interconnections with neighbouring utilities, PEI, Quebec, Nova Scotia, and New England, and is planning another 345 kV tie to Maine. Generation types include nuclear (15.2%) (Point Lepreau), residual oil (40%), natural gas (6.9%), orimulsion , coal (12.8%) and hydroelectric (20.5%).

Newfoundland and Labrador

Newfoundland and Labrador have about 1,600 MW of peak load and about 1,920 MW of supply on the island and about 437 MW of peak load in Labrador. The loads are supplied from a combination of hydroelectric and oil-fired generation. Recently the oil component has been increasing (about 35% in 2003). The Churchill Falls generation (total 5,428 MW, approximately 34 TWh per year), was developed largely under contract to Hydro-Québec.

3.3.5.3 Negotiations on Imports

Recent discussions have taken place leading to the tendering of bidders to develop two new sites on the lower Churchill River. One site is 225 kilometres down river at Gull Island (2,000 MW, 11.9 TWh/ year) and another site is further down (60 kilometres) at Muskrat Falls (824 MW, 4.8 TWh/year). Ontario, in cooperation with Hydro-Québec and SNC Lavalin has submitted a preliminary proposal to develop the site and purchase its output or, alternatively, just purchase the power. Depending upon the outcome of the bidding process, most, if not all, of the resulting additional power and energy could be shared by Hydro-Québec and Ontario.

Importing power and energy from external jurisdictions comes with some considerations that are not required when dealing with Ontario generation, conservation or demand management. The regulatory climate, and strategic interests of the source area may become factors in the price, as will the source area supply conditions, reliability, timing, and delivery paths. Firm power exports from the U.S. require Presidential Permits and large deliveries are likely to require new transmission facilities, which can be affected by NIMBY (not in my backyard) and other permitting problems.

Since it is imprudent to believe that the power will be delivered if the source area is short of supply for the source area's own load, the reliability and planning of the source area must

receive careful scrutiny and will be addressed in the purchase contract. The NAFTA agreement also creates binding conditions for firm exchanges that can be problematic for the seller and a source of uncertainty for the buyer. Nevertheless, when a situation exists where a willing seller can benefit from selling power and energy to a willing buyer, who also benefits, it is possible to negotiate good exchanges.

In terms of planning the power system, a purchase is counted as a power resource only if it is a FIRM purchase. This usually means that the seller agrees to hold the amount of the sale aside for the purchaser and will plan its system to a sufficient level of reliability that the purchase amount has the same reliability as if that amount were part of its native load.

Even then, if the transmission path for the purchase is very long or unreliable, the purchase may be discounted to allow for its possible loss when needed. Losses on long transmission delivery paths are also a factor that must be considered. A purchase of energy only, without the capacity being firm, can be used to improve energy economics and possibly the environment, but does little or nothing to meet increasing capacity demands.

Purchases from adjacent jurisdictions that utilize existing facilities are obviously the easiest to bring to fruition. The involved utilities are accustomed to working with each other, know each other's systems and can frequently arrange delivery without huge transmission costs and problems. Ontario has a long record of working with Hydro-Québec and Manitoba Hydro to arrange short-term purchases over existing facilities and a few longer-term purchases as well.

In 1989, Ontario Hydro and Manitoba Hydro had committed to a long-term purchase from a new facility to be constructed at Conawapa in northern Manitoba. Unfortunately, the severe recession in the early 1990s reduced projected load growth to the point that the purchase was cancelled by Ontario.

The overall desirability of that purchase has returned with subsequent load growth and the decisions to replace coal-fired generators in Ontario. A new attempt to arrange purchases from Manitoba, including the Conawapa purchase, is now underway. Such a purchase would also require a major investment in transmission to deliver power to the load centres.

However, the transmission path for the purchase also makes it a significant link in a potential trans-Canada, inter-provincial grid, an initiative that is receiving attention from several provincial governments and the federal government. One of the longest segments of a trans-Canada grid is the one through northern Ontario. If that piece were in place, a major obstacle would be overcome.

Purchases from Hydro-Québec, although somewhat closer to Ontario's main load centres, have other issues that must be addressed. The need to interconnect with Hydro-Québec through direct current interconnections for major purchases introduces the large costs of conversion from AC to DC and back again.

The U.S. market in New England and New York is characterized by high energy prices, so that Ontario needs to compete on price in order to win a contract with Quebec. The Maritimes also have had somewhat higher cost structures. Nevertheless, it appears that the possibility of Ontario and Quebec working together to develop new generating facilities in Labrador on the Churchill River is providing an opportunity to share in the costs and benefits of that project in a manner that appears attractive for the supply to Ontario.

Going beyond adjacent jurisdictions for a purchase contract almost always involves engaging the adjacent jurisdictions in the contract negotiations because of the need for a transmission path for delivery. In the past it has been very difficult to bring such a deal to fruition because of complexity and costs, but the desire to cut greenhouse gases and improve overall efficiency and market mechanisms will drive negotiators to try harder and there are some interesting possibilities.

Alberta's tar-sands oil recovery operations are voracious consumers of natural gas to provide heat to soften the bitumen. This is a very large and important opportunity to use cogeneration to provide both large amounts of electric power and also the heat required for the processes. There are proponents in Alberta that are looking seriously at shipping power from the tar-sands developments all the way to California, which is a long distance and comparable to moving energy to Ontario. Some strategic planning and negotiating might lead to delivery to Saskatchewan-Manitoba-Ontario instead.

If a major transmission line is to be constructed to incorporate Conawapa output into Ontario, some extensions to the line could make the purchase of cogenerated electricity from Alberta feasible. In addition, Saskatchewan is blessed with large deposits of lignite, a coal-like fuel, which it uses for much of its generation. Saskatchewan is looking at "clean lignite" generation in the future.

The possible use of such energy on a broader basis could improve the security, through improved diversity, of the electricity supply in central Canada, and Ontario. Alberta, similarly, has abundant coal resources and is considering "clean" techniques for exploiting both some of the energy from its tar sands and also its coal. Both Saskatchewan and Alberta have opportunities for using carbon dioxide for enhanced oil recovery. Saskatchewan already has a pilot project that has been operating for many years. This will allow the capture (sequestration) of carbon dioxide.

It is necessary to note that many of these activities could lead to substantial decreases in greenhouse gas emissions and thus be eligible for federal assistance or credits. Such credits would also be consistent with the long-term desire the federal government has expressed to see stronger inter-provincial ties. Under these conditions a federal government subsidy to improve the basic economics might be justified.

At first glance, it might seem unlikely that a major new firm purchase would come from the U.S. However, in the open marketplace that is now in effect, profit can motivate outcomes that sometimes seem unlikely. There are still huge reserves of coal in the U.S. and there is a strong push on now to exploit these resources using new "clean" technologies to reduce the U.S. dependence on imported oil and gas. In addition, nuclear units are being refurbished and will provide energy to the marketplace.

The future purchase of power from the U.S. under a firm contract should therefore be retained as a possibility. Ontario's U.S. neighbours have been good neighbours, providing emergency assistance on many occasions and cooperating in planning and operating the combined power system that we all share. Consideration could be given to placing a well-designed RFP in New York, Pennsylvania, Ohio, Minnesota or Michigan for clean energy.

One consideration to be recognized is that any firm purchase where no additional interconnection capability is built, will reduce transfer capability from other interconnected sources. Moreover, a firm purchase, in common with a new generation source within the province, may create additional loading on internal circuits in Ontario. The transmission system near Niagara, for example, is very heavily loaded and the addition of a firm purchase using this path might not be viable, without the addition of new transmission reinforcements.

3.3.6 Ontario Transmission System Characteristics

Historically, the need to have central large-scale generators, sometimes in remote locations from the load, drove the need to have transmission and distribution systems. The early ones were direct current (DC). However, the voltage levels and energy losses in practical applications were unacceptably high. Under alternating current, transformers could be used to change the voltage up or down as required.

In using transformers, if the voltage is stepped up by a factor, then the current is stepped down by the same factor. Since line losses for a given line are proportional to the *square* of the current, the higher voltage lines can move power for longer distances without incurring undue losses of voltage and energy. With this arrangement, for instance, large generating stations on the Ottawa River and in the northern part of the province can deliver low cost power and energy to the load centres in the Golden Horseshoe area.

As time progressed, loads grew, more generation was needed, and the transmission system became networked into a kind of grid in order to serve geographically diverse areas and incorporate new supplies. The amounts of power required to be transmitted increased and the transmission system grew through a number of increasing voltage levels, beginning at about 69 kV and progressing through 115 kV, 230 kV and 500 kV.

Facilities operating at these various voltages need to be interconnected with each other to form a single grid. This requires extensive use of transformers, as shown in Table 3.3.3:

Table 3.3.3 - Typical Transformation Voltages and Their Application

High Voltage	Low Voltage	Normal Use	Comment
500 kV	230 kV	Join system transmission levels	Usually in major transformer stations
500 kV	115 kV	Same	Same
230 kV	115 kV	Same	Same
230 kV	345 kV	Interconnections	Same
230 kV	27.6 kV	Step down to area supply	Area supply transformer stations
230 kV	44 kV	Same	Same
44 kV or 27.6 kV	8 kV or 4 kV	Step down to distribution level for local delivery	Smaller stations local to loads
230 kV, 500 kV, 115 kV	12 kV (or other generator terminal voltage)	Generator step-up transformers	In generating stations to raise voltage from generator level to transmission level.

Source: OPA

In most cases the voltage ratio of the transformers can be changed slightly to suit different applications and system conditions. In some cases provision is made to have the ratio changed while the transformer is operating so that local voltage conditions can be adjusted to best suit the needs of the power system and its customers.

Voltages below 69 kV are considered distribution voltages (50 kV for regulatory purposes in Ontario) and these are typically the circuits that can be seen at the tops of pole lines along the roadside. High power deliveries usually involve “three-phase” circuits. For observation purposes this means that there are either three or four separate conductors (wires) per circuit.

Initially, when the objective was simply to transmit power from the generators to the loads, lines tended to be built in as straight a line as possible between the two points. However, as the network became more complex with growing loads and supply systems, the objective changed to one of planning new generation, as much as possible, to avoid having to build major transmission.

For thermal generation, the availability of a good cooling water source is important to generating efficiency, and the generating facilities located around the Golden Horseshoe (Lakeview GS, Pickering GS, Nanticoke GS and Darlington GS) enjoy the benefits of the cold water of the Great Lakes. These facilities are also located in proximity to the major loads, which reduces the need for expensive transmission infrastructure.

The transmission of alternating current (AC) power is subject to a number of design considerations. For example, the amount of power that a given transmission path can carry is limited, sometimes critically, by conductor temperatures as the current warms the conductors.

There are standard clearances above the ground that must be maintained for safety and reliability reasons.

Maximum thermal rating of lines is limited by the maximum sag allowed before clearances become unsafe. Conductor temperature is mostly a problem on hot, windless, bright sunny days in the summer – unfortunately the same time when air conditioning load tends to peak.

Other factors that limit the power a circuit can deliver are the length of the circuit and the system operating voltages.

Maintaining good system voltages and avoiding either long circuits or circuit outages on delivery paths that are heavily loaded is critically important to the operation of power systems. Both of these issues are currently threats to the reliable supply to much of the Golden Horseshoe, and could become worse if coal-fired plants (notably Nanticoke GS) are retired before the means to maintain voltages and flow levels are in place. Nanticoke is a major source of voltage support to the Golden Horseshoe area, as are the other large generators in the area.

In the absence of generation, another source of voltage support, Shunt Capacitors can be used but offer less flexibility than generators. Many of these have already been installed to avoid building new transmission near Toronto, and many more are in the planning stage now.

Another technique, not commonly used in North America, is to install "series capacitors" in transmission lines. Their purpose is to increase the maximum power flow of the circuits. In simple terms, series capacitors seem like the ideal solution, but in practice they are very complex to design in a manner that provides a reliable solution to the problem. There are plans to install them in several major southern Ontario lines to avoid the need to construct new facilities with the attendant long lead times, environmental hearings and costs that would be otherwise needed.

At local step-down facilities where power passes from the bulk transmission system to the area supply facilities, the transformer stations usually include on-load tap changers on the transformers. These are used to ensure that local voltages can be maintained at tightly controlled levels so that customer equipment is not impacted by voltage variations. Motors, computers, and other types of electrical equipment can operate badly or be damaged by wide voltage variations. Where necessary, shunt capacitors may be installed locally to improve the area supply voltage regulation.

The IESO's "10-year Outlook" and Hydro One Networks' "10-Year Transmission Plan" both provide extensive detail on the problems, the available solutions and the limits on the solutions facing Ontario. The challenges to maintaining a reliable, economic power supply, particularly in southern Ontario, are truly daunting at this time.

The incorporation of new major generation into the Ontario supply will require that the

transmission system be adequate to provide reliable and safe delivery of the power to the loads. Distributed generation may be incorporated, if planned carefully, to lessen the requirements for transmission upgrades, by siting the generation closer to the loads.

3.3.7 System Reliability Planning Parameters

There are several crucial interrelated factors which, aside from economics and the environment, dominate selection of the viable alternatives.

Reliability has been a factor in power system design since the use of electricity grew to being a major factor in our homes and places of work. However, on November 9, 1965, a major blackout shutdown the entire power system of the northeast U.S. and most of eastern Canada. Not surprisingly, there were major political repercussions from this blackout.

Unfortunately for Ontario, the cause was an improperly set protective relay at a Niagara area transformer station, so the pressure to make sure "it never happens again" was acute for the former Ontario Hydro. Subsequent to this event, system planning and operating standards were tightened up through all of North America and today the North American Electric Reliability Council (NERC) reviews the planning in each of 10 Regional Reliability Councils (RRCs) covering all of the continental U.S. and most of Canada.

Ontario is contained inside the territory of one of these RRCs, the Northeast Power Coordinating Council (NPCC). NPCC includes almost all of eastern Canada, New England, and New York. As a member interconnected with other members, Ontario is obligated to maintain strict adherence to planning and operating standards developed by NPCC and the potential costs of violating the standards can be high in term of operation and in terms of censure by other members.

After recent major outages the political interest is high, and recent U.S. federal reliability legislation will lead to oversight of reliability issues in the U.S. by the U.S. federal regulators. Ontario has, and will continue to have strong enforcement authority for reliability standards through its market rules.

The standards cover a wide range of areas. They include the amount of reserve that is required in different operating timeframes, the reliability criteria for designing the generation and transmission system and the preparedness for major system events. Properly followed and monitored, the standards provide for each utility area taking its fair responsibility, not only for its own load, but for avoiding disruptions to neighbouring jurisdictions. These standards tend to dictate the details of how the system operators go about cutting loads to maintain an operable power system under shortage or overload conditions.

The IESO currently oversees reliability of Ontario's power system, adhering to the standards set by NERC and NPCC, and enforcing compliance with the standards of all entities in Ontario under the market rules.

The standards are lengthy and too complex for this report but there is one requirement which will have a direct impact on planning the power system. Power system planning is required to result in a planned system having a Loss of Load Probability ("LOLP") of one day in 10 years. This calculation is complex and is affected by a number of factors, this includes generator reliability, annual load shape, generator size, available load reduction measures (that can be employed to reduce the requirement under shortage conditions), and importable power in emergencies. The calculation provides an index, the LOLP which, for simple explanation purposes, corresponds to the probability that the peak load will need to be interrupted in order to maintain a stable supply-demand relationship.

By trial and error, with different supply/demand options, the required reserve level can be determined using this calculation method. This is the manner in which detailed system plans are established for specific additions.

The labour and time required to use this technique are neither justified nor required to deal with the matter of the recommended generation mix. Since an 18% reserve is the approximate reserve associated with a LOLP of one day in 10 years, and because other similar utilities have similar reserve percentages. In this supply mix study, OPA has decided to use an 18% reserve requirement as a proxy for the required LOLP requirement. Subsequent detailed planning of specific options may result in some variations from this number, but the main purpose of the study can be attained without the extremely time-consuming work required to do the reliability calculations for generation options that are not defined by location at this time.

One consideration frequently overlooked in reliability reviews and not incorporated in standard computerized reliability tests, is that of "common-cause" or "common-mode" failures. Common-cause failures are failures that result from some single source of damage or failure (such as a tornado crossing a 500 kV right-of-way and taking one or more circuits is a typical example). Other causes can be relatively small but disastrous failures of control or protective relaying that can cascade and cause many system elements to be tripped out of service or be adversely affected in some other way. Some of these issues are addressed by the NPCC design requirements and efforts are made to reduce such susceptibilities. However, not all such events can be foreseen, much less planned for, and history shows that some of the most serious conditions that have occurred on the power system have resulted from these types of events.

While it is difficult to prove definitively, most observers would agree that a system that is built to meet the NPCC reliability requirements and designed to be robust is more likely to survive these events than one that is consistently skirting the edges of failure. Unfortunately, many power systems in North America have become more highly loaded since the electricity markets opened in the 1990s and the margins are thinner than they were previously.

There have been recent improvements, for example, in system control facilities. These improvements have allowed system operators to "see" what is happening in adjacent systems, and as a result be better able to anticipate and remedy potential disruptions arising in adjacent systems.

One of the major factors in determining the need for and type of new generation (and transmission) is the load factor of the system load. The load factor for a specified period is defined as the average power consumed during the period divided by the peak demand during the same period. Thus there are annual load factors, monthly load factors and daily load factors.

The principal driver influencing the growth of load factor is loads that peak together. The main drivers among these are air-conditioning load, heating load, industrial load, and domestic load. In most cases adjusting these loads means time-shifting electricity use, so that turning off air-conditioning loads for 20 minutes over the peak periods usually means that the affected facilities will require the air-conditioning to run a bit longer when it is switched on again.

Nevertheless, load shifting can avoid the need for additional peaking generation that would otherwise be required to supply the short duration peak loads. This is a desirable objective if it can be accomplished without undue or uneconomic customer disruption. Incentives to persuade customers to install the required load shifting controls can be justified by the avoided cost savings.

Decreasing the base load electricity use by embarking on an energy conservation program may also affect the load factor to some degree. This depends on the targeted loads. Reductions in this way can also reduce the large capital costs associated with base load generation alternatives, as well as the primary energy and production costs, and environmental costs for the avoided energy production.

There are many ways to achieve reductions in peak load, but one highly useful to the system operators in maintaining the required reliability conditions is "dispatchable" load. This is load that can be reduced or cut quickly either by direct remote control from the IESO control room or by calling the customer and directing the reduction. This type of load reduction is applicable to certain types of load.

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3.4 Conservation and Demand Management Issues

The purpose of this section is to place Ontario's demand for electricity in the perspective of demand in Canada and the U.S. to explain the various forms of Conservation and Demand Management (CDM) and the criteria and rationale for CDM programs to present the additional context of demand and electricity intensity trends in Ontario, and finally to provide an overview of CDM experience in Ontario.[1]

3.4.1 Key Findings

- CDM activities fall into conservation (absolute reduction in use), energy efficiency (achieving the same function using less energy), and load management (shifting use to different times or interruption of use at peak times)
- Energy efficiency gains can be achieved through new codes and standards for manufacturing appliances and for new buildings, and by providing financial incentives for end users to switch to more efficient products and services
- Load control initiatives include critical peak pricing policies, load interruption agreements and consumer responses to requests for demand reduction
- CDM involves intervention by an authority, such as a government or regulator, to introduce new codes or standards, or to provide direct financial incentives and/or information
- Savings from CDM are supplemented by those from market mechanisms, such as an energy services company that provides more efficient equipment to an electricity user in exchange for a share of the resulting savings, or an electricity user that bids demand reduction into the Ontario spot market (i.e. agrees to curtail consumption in return for financial compensation)
- The Ontario context for CDM includes continuing absolute growth in the demand for electricity, but ever lower electricity intensity. That is, more goods and services are produced for a given level of demand for electricity (decreasing electricity intensity)
- High growth in commercial and institutional electricity demand is due mainly to lighting, which remains a promising area for CDM programs. This rate of demand growth has outpaced advances in efficient lighting and other electricity end uses
- Residential and commercial air conditioning loads have doubled since 1990; this is one of the most promising areas for large DSM gains
- Ontario Hydro's large-scale DSM/CDM programs of the late 1980s were cancelled in the early 1990s; however, DSM/CDM initiatives have continued at the municipal and federal levels

[1] This review draws upon a study by ICF Consulting commissioned by OPA, entitled "*Factor Analysis of Ontario Electricity Use 1990 to 2003*".

3.4.2 Introduction

Conservation and demand management (CDM) refers to a range of activities designed to influence the use of electricity by consumers, either by reducing overall electricity consumed, using electricity more efficiently, or by shifting usage to other times such as off-peak hours. CDM can be designed to bring about desired changes in overall system load or the variation in load over a specific time period (load shape).

CDM involves intervention by an authority, such as a government or regulator, to introduce new codes or standards, or to provide direct financial incentives or information. Savings from CDM are supplemented by those from market mechanisms, such as an energy services company that provides more efficient equipment to an electricity user in exchange for a share of the resulting savings, or an electricity user that bids demand reduction into the Ontario spot market (i.e. agrees to curtail consumption in return for financial compensation).

The CDM activities illustrated in Figure 3.4.1 are often distinguished between conservation, efficiency, and load management[2]. These activities can be defined as:

- Energy conservation – activities that result in less energy being used than would normally be the case.
- Energy efficiency – activities that result in using less energy to perform the same function.
- Load management – activities such as shifting energy use to different times, or the interruption of energy use to reduce demand at peak times.

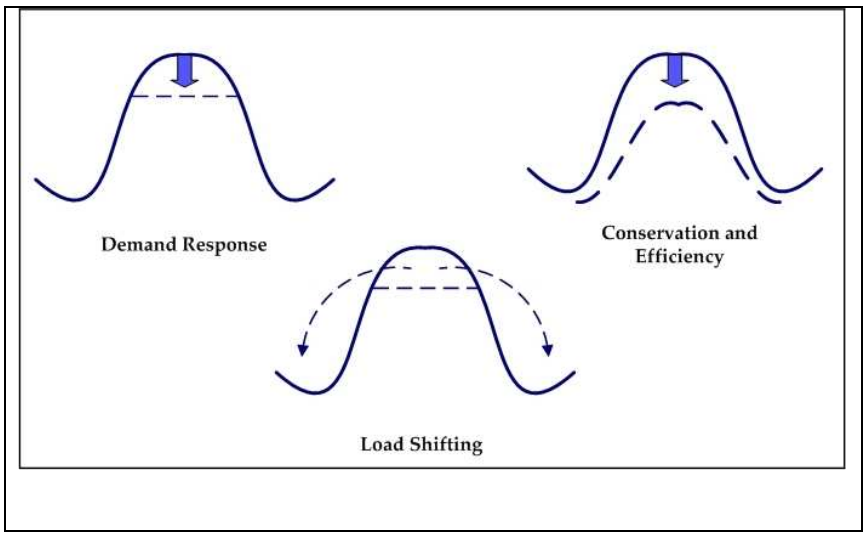
3.4.3 Ontario Demand in Comparative Perspective

Canada is the largest per capita electricity consumer among the G7 nations. This is explained, in part, by Canada's economy being heavily weighted toward resource extraction and energy intensive primary industries, a larger geographic area and low population density, a climate with cold winters and hot summers, as well as a relatively high standard of living. Examples of such industries include resource extraction, forestry, steel and petrochemicals.

The graph in Figure 3.4.2 shows that Ontario, when compared to other North American jurisdictions, has lower per capita energy consumption. Ontario's consumption level is significantly lower than the Canadian average and has dropped below that of the United States, but higher then that of California.

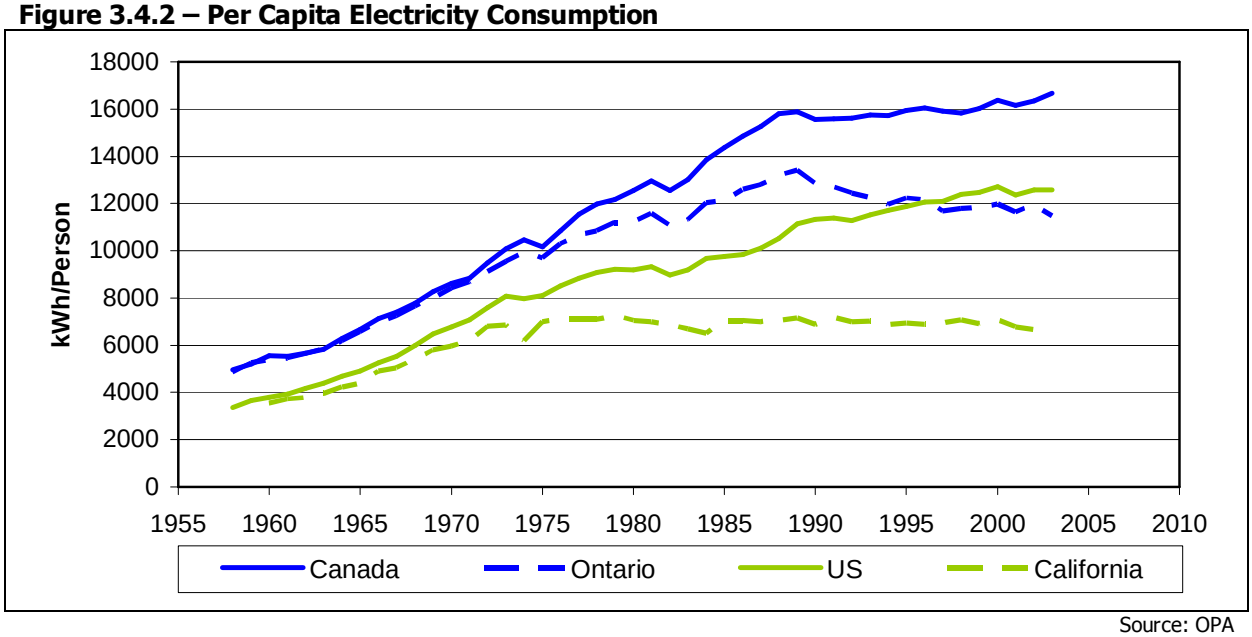
[2] OEB (Ontario Energy Board), 2004. "*Demand-Side Management and Demand Response in the Ontario Energy Sector*", Report of the Board to the Minister of Energy, RP-2003-0144

Figure 3.4.1 – Conservation and Demand Management



Source: OPA

Figure 3.4.2 – Per Capita Electricity Consumption



Source: OPA

3.4.4 CDM Resource Types

The CDM resources that can alter demand fall into two categories. First, there are load control initiatives, which are activities that can be utilized when needed. Critical peak pricing policies, load interruption agreements for appliances, and consumer response to requests for demand reduction, such as from the IESO, are examples of load control. Second, there are total energy

use initiatives, which are the ones that influence electricity demand over a longer time frame. These would include time-of-use (TOU) pricing policies, codes, standards and product labelling. Each of these would include conservation and efficiency measures which affect total consumption and peak demand over a longer time frame.

The length of time necessary to get results is an important consideration when planning CDM programs, as different reaction times are associated with different approaches. Energy efficiency programs and standards, for example, require some 'ramp up' time for the energy efficiency measures to penetrate the stock of electricity consuming equipment, while the load shifting benefits of time-of-use rates may be realized within weeks of implementation.

Table 3.4.1

→ CDM Reactions Time →		
Minutes/Hours →	**Days/Months →**	**Months/Years**
Load Control	Pricing Policies	Energy Efficiency Programs
Direct Load Control	Critical Peak Pricing	Codes and Standards
Customer Control	Time-of-Use Rates	Education and Public Awareness
		Labelling

Source: OPA

When planning CDM resources, the timing, amount, persistence and location of the program leads decision-makers to distinguish forms of CDM between firm or predictable and less firm or less predictable resources.

On the one hand, measures such as load control and standards drive energy efficiency and can be viewed as firm resources because they are more predictable and have more 'dispatchable' savings. On the other hand, conservation measures and public education campaigns are considered less firm resources because the reliance on behavioural modification can have much greater uncertainties than, for instance, contractual arrangements. An indication of the certainty available for load control is evident in the contracts between the IESO and large consumers of electricity. They lead to rapid, certain demand curtailment in response to a notice from the system operator.

3.4.4.1 Load Control

Load control has the primary objective of improving system reliability and is conducted by the system operator.

Direct load control refers to the active interruption of customer load by the system operator and is generally applicable to industrial and commercial consumers. In the residential sector it is usually targeted at individual appliances or equipment on residential premises. Examples of direct load control include residential air-conditioners and hot water heater cycling.

Customer control refers to an agreement by the consumer to curtail electricity use in response to a notice from the system operator. Customer control typically involves industrial consumers.

3.4.4.2 Total Energy Use

Energy Efficiency has the primary objective of reducing total energy use to obtain the same level of service. Peak power consumption may be reduced as well. The main drivers for energy efficiency are standards and codes by which appliances are manufactured and buildings are constructed. Energy efficiency programs and strategies can include financial incentives and financing alternatives for energy efficiency upgrades, the direct provision of products or services, as well as information, training and education programs.

Codes and Standards have the primary objective of reducing total energy use, but may also reduce peak power consumption. They can include minimum efficiency standards for appliances or codes, such as building energy codes. Different end uses may also be targeted, such as lighting, Heating, Ventilation and Air Conditioning (HVAC), water heating, windows and insulation. The impacts of codes and standards will accrue slowly as products are replaced, new buildings are constructed, and existing buildings are remodelled or retrofitted.

Critical Peak Pricing has the primary objective of improving system efficiency, and is provided by the load serving entity (LSE) under regulatory supervision. Agreements with customers will determine the maximum number of hours the consumer is exposed to critical peak pricing, usually in hours per month and days per year. California, in particular, is piloting a state-wide critical peak pricing policy.

Time of Use Rates (TOU) have the primary objective of improving system efficiency. They are also under the responsibility of the load-serving entity, under regulatory supervision. Pricing policies are intended to impact the electricity system by shifting load to other time periods, and reducing system peak usage, but not necessarily total energy. Enabling technologies, such as Smart Meters as proposed in Ontario, can expose consumers to their real-time electricity demand to encourage demand response by shifting consumption to off-peak hours.

3.4.5 Criteria and Rationale for CDM Programs

Integrated Resource Planning

The emergence of integrated resource planning[3] (IRP) resulted in giving planning for the future of electricity demand an even footing with planning future supply. As a means of simply

[3] See Part 2.4 for additional discussion of IRP.

addressing tight supply/demand conditions, CDM can play a role as equally important as installing supply options, especially in times of suddenly changing needs. As part of an overall IRP framework, the objectives of CDM are much broader than just addressing supply/demand.

Some of the other objectives of CDM may include improved system reliability and market efficiency, risk management, reduced environmental emissions, lowered transmission constraints, deferred need for new generation capacity and associated capital investment. Benefits of CDM programs for end users include savings on their energy bills, lower chances of supply disruptions, as well as a cleaner and healthier environment.[4]

Total Resource Cost

The effectiveness of any particular CDM program can be assessed by applying a Total Resource Cost (TRC) Test, whereby the total costs and benefits to all parties are compared. If the benefits exceed the costs, the CDM program is said to be "economic", and appropriate regulatory accommodation is made to ensure that neither the supplier nor the customer is disadvantaged.

The TRC Test allows utilities to evaluate and select from programs that are cost effective. In addition, financial mechanisms such as the Lost Revenue Adjustment Mechanism (LRAM) and Shared Savings Mechanism (SSM) link utilities' profits with their ability to reduce their customers' energy bills through CDM activities.

Ultimately, the rationale for effective CDM programs is that they represent a toolbox for the active management of demand growth and load profiles to meet economic and environmental objectives. Without goals, policies and programs in place for CDM initiatives, customers see little incentive to engage in energy efficiency, and utilities gain little reward, or are penalized, for administering CDM programs to their customers.

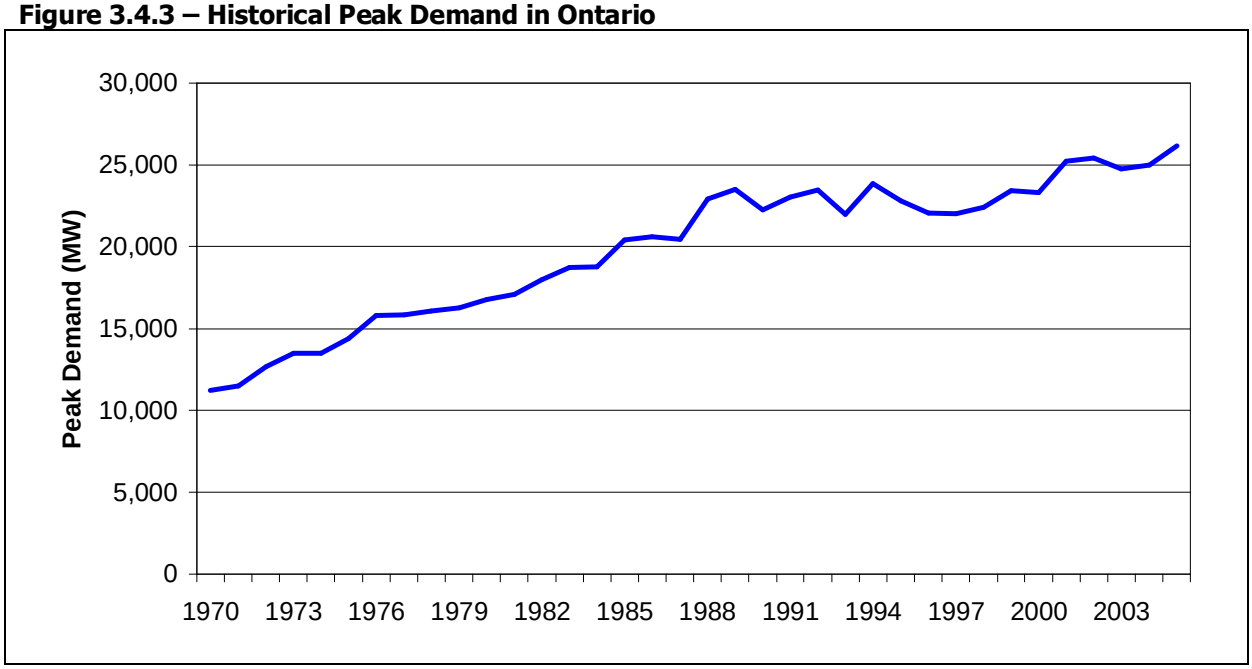
Over time, CDM may emerge as a means toward gaining a competitive edge in the energy services market in Ontario; however, in the present context, interventions by government and/or a central planning agency are required to ensure the effectiveness of CDM programs to result in their desired outcomes.

3.4.6 Current and Forecast Demand for Electricity

CDM programs need to be grounded in today's consumption of electricity. Ontario continues to experience increases in demand and energy use. While growth has moderated relative to historical levels, demand is still forecast to grow in the future. The following two figures illustrate the historical growth in peak demand and electricity demand in Ontario.

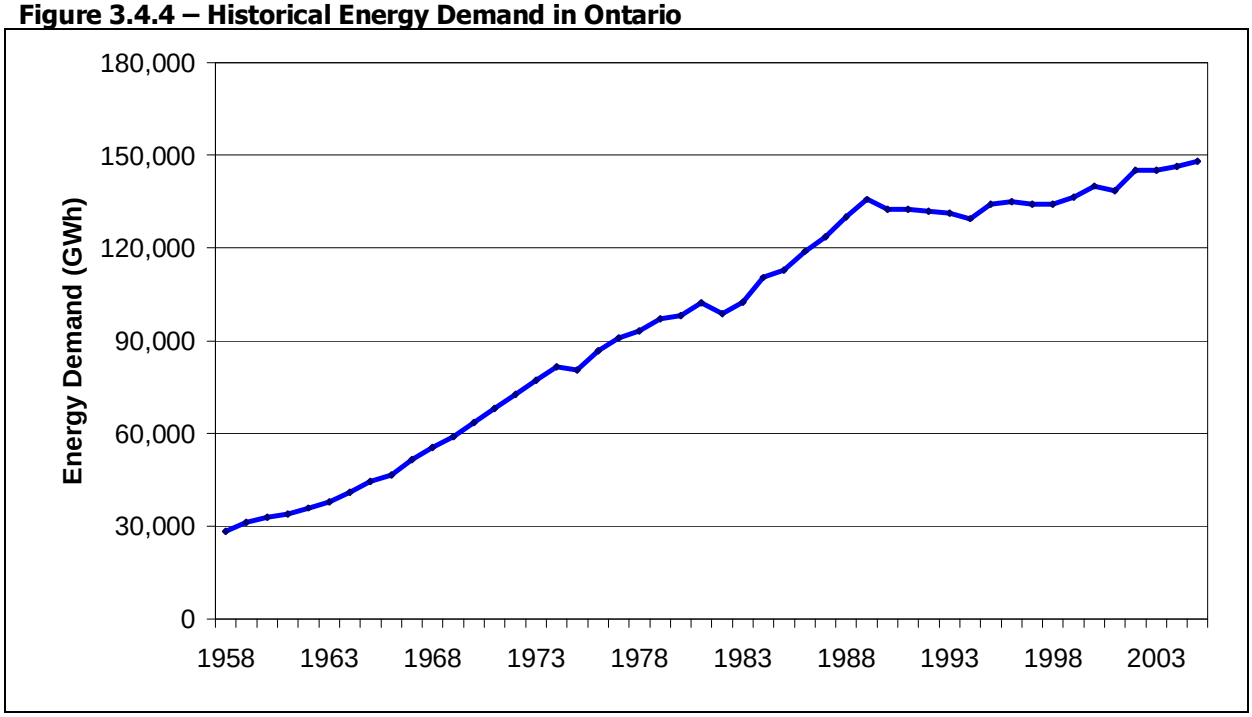
[4] See Part 2.4 for additional discussion of IRP.

Figure 3.4.3 – Historical Peak Demand in Ontario



Source: ICF

Figure 3.4.4 – Historical Energy Demand in Ontario



Source: ICF

Electricity load may be broken down into the contribution of the residential, commercial and industrial sectors, as well as by the various sub-sectors. Factors such as industrial mix and climate will have significant impacts on electricity use within a given economy or jurisdiction.

Services and Residential Sectors

The most rapid growth in consumption has been in the commercial and institutional services sectors. Within this sector, lighting is the single largest end-use, accounting for over 37%. Although 43% of commercial buildings have reported using energy efficient ballasts and over 31% now use energy efficient lamps, the lighting load per square meter of floor space has increased. Increased activity in these sectors has been responsible for increased lighting intensities, despite having higher efficiency lighting systems.

In addition to the services sector, residential and commercial electricity consumption has increased, largely from the air-conditioning load having more than doubled since 1990. In addition to changes in lifestyle, hotter than average summers over the last 15 years have contributed to the increase in the air-conditioning load. Air conditioning represents one of the most promising areas for making large gains in CDM through the use of more efficient equipment.

During this period, electricity rates were largely frozen. This had the effect of shielding consumers from the true cost of electricity and eliminating incentives to conserve their use of electricity. In other cases, building owners have had little incentive to buy more efficient lighting stock, as tenants typically pay the electricity bills.

Industrial Sector

Although commercial and residential use has increased, the industrial use of electricity has been declining. This has been both because of structural changes, such as a shifting away from primary and resource extraction toward secondary and value-added industries, in addition to efficiency improvements. The statistics are striking:

- actual electricity use by industry has decreased by almost 10% since 1990;
- industrial electricity use would have increased 31% since 1990 if structural change had not occurred (and the proportional demand of the residential, commercial and industrial sub-sectors remained the same as in 1990); and
- industrial electricity use would have grown by 20% if electricity intensity associated with various activities had not changed over the same period.

As the above data shows, the influence of structural changes in the economy on electricity use can be quite dramatic. As a consequence, it can be very misleading to compare uncritically the intensity of electricity use across jurisdictions. This represents a significant challenge and source

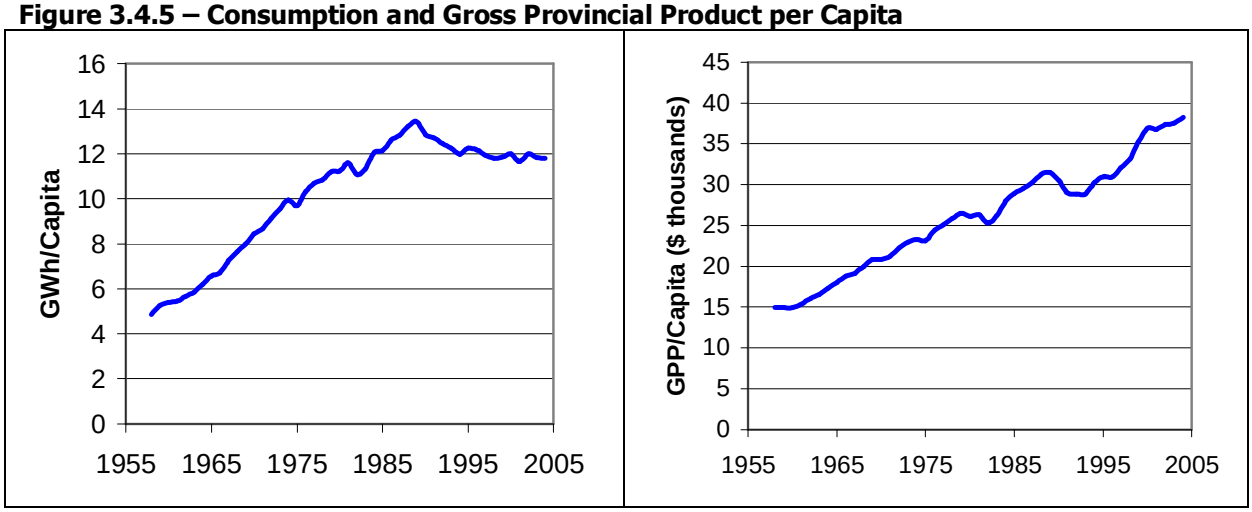
of uncertainty for the current exercise, given that only limited analysis of the detailed use of electricity in Ontario has been conducted over the past decade.

3.4.7 Ontario's Declining Electricity Intensity

CDM programs in Ontario are also informed by the trend in electricity intensity. As described in the previous section, demand for electricity in Ontario has grown since 1990. However, this growth has been accompanied by a striking improvement (decrease) in electricity intensity that started in 1990. This means that Ontario's economic output has grown significantly faster than the demand for electricity. Electricity intensity is the ratio of electricity output (kWh) to economic output measured by the Gross Provincial Product (GPP). This trend is expected to continue in the future.

It is illustrative in examining electricity intensity first to examine consumption (energy demand for electricity) and economic output (GPP) on a per capita basis as shown in the following figures.

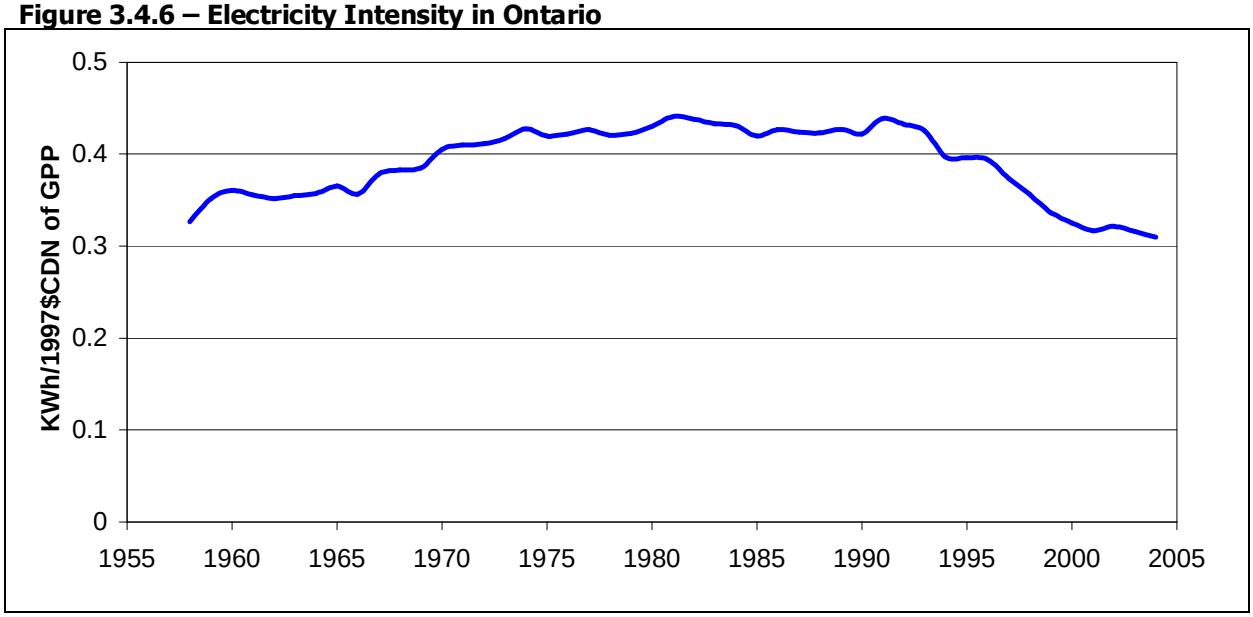
Figure 3.4.5 – Consumption and Gross Provincial Product per Capita



Source: ICF

It is seen that while GPP per capita has grown steadily, consumption per capita is on a slow decline. When these two trends are combined in Figure 3.4.6, there is seen to be a dramatic fall off in electricity intensity in Ontario since the early 1990s.

Figure 3.4.6 – Electricity Intensity in Ontario



Source: ICF

Figure 3.4.5 indicates that in the period from 1958 to 1974, electricity consumption grew faster than the economy. During this time, consumption grew at a strong rate of 6.8% per year while the economy grew at 5% per year. The strong growth in electricity consumption during this period can be attributed to the continuing diffusion of electric technology in Ontario. For example, the growth in housing spurred a marked increase in electric space and water heating. Appliance ownership grew rapidly. Ontario Hydro's marketing slogan "live better electrically" characterized this period accurately. Conservation was not a consideration for most consumers of electricity or for the planners of the electricity generation system.

The period from 1974 to 1993 differed in that electricity consumption and the economy grew at roughly the same rate, around 2.4% per year. During these years there was a strong connection between electricity consumption and economic growth. With this strong correlation, the assumption developed for forecasters and planners that future GPP growth was a direct indicator of future electricity consumption.

In contrast to the preceding period, the years 1993 to 2004 marked a "decoupling" between electricity consumption and economic growth, as consumption began to grow at a slower rate than the economy. Electricity consumption grew modestly at below 1.0% per year while economic growth was stronger at 4.1% per year.

In summary, the years 1958 to 1974 were characterized by increasing electricity intensity of the Ontario economy, followed by a "levelling off period" from 1974 to 1993. Electricity intensity declined after 1993 for two reasons: energy conservation and industrial restructuring.

- Conservation/Energy Efficiency – slowly began to take an increasing role through the availability of more efficient appliances and the growth of conservation awareness brought about in part by Ontario Hydro's conservation programs.
- Structural effects – changes in the nature of activities within each sector as well as different relative growth between sectors that further affected the electricity intensity and contribute to the decoupling.

Since 1990, the energy efficiency of residential appliances has improved dramatically, by over 40%. However, the improvements of refrigerators, freezers and dishwashers have been counteracted to a degree by increased capacity (larger refrigerators, larger homes) and increased use of air conditioning, home electronics and other non-major appliances, as well as lighting.

While these results can be attributed to improved efficiency with no market intervention, they may in part be attributable to standards. In Canada, the federal government adopted the EPA's "Energy Star" program shortly after it was first adopted in the U.S. in 1992. These results could have also been due, in part, to CDM measures introduced by Ontario Hydro in the late 1980s and terminated in the early 1990s, but which provided ongoing efficiency gains as stock was replaced, and transformed markets and practices.

There essentially have been no major province-wide CDM initiatives in the electricity sector at the provincial level during the 1990s. However, active CDM initiatives were developed for Ontario's natural gas utilities in the 1990s, meaning that consumers have maintained ongoing awareness of energy conservation. In addition, some municipalities placed their own efforts behind CDM for electricity. Also, prior to electricity's market opening in 2002, many industrial and commercial customers contracted for expertise in furthering their understanding of electricity usage, which was primarily motivated by the foresight of having to negotiate and contract for their own electricity supply. This was a result of enterprise acting in its own best interests, rather than due to formal CDM programs or initiatives.

3.4.8 CDM Experience in Ontario

Recent CDM experience in Ontario can be separated into the periods before the creation of a competitive market and the period that followed the creation of a hybrid competitive-regulated market.

In the earlier period, which started in the mid-1980s, Ontario Hydro embarked on an extremely ambitious large-scale Demand Side Management (i.e. CDM) program. It was directed largely at delaying major new generation additions that were predicted for the period following the year 2000. Approaching the early 1990s, a recession hit Ontario and, suddenly, there was an apparent abundance of generating capacity for the foreseeable future. Due to the economic downturn and

resulting surplus generating capacity, priorities shifted toward dramatically constraining costs, especially for new resources, which led to the cancellation of new resources, including both generation and CDM programs.

The cancellation of CDM programs at the provincial level did not preclude similar initiatives at municipal levels. In 1990, the City of Toronto opened its Energy Efficiency Office to develop an energy efficiency and conservation strategy for Toronto. The last fifteen years has seen Toronto's Energy Efficiency Office grow to administer and coordinate several programs and services, such as providing technical support to the industrial, commercial and institutional sectors, residential energy awareness programs, and the Better Buildings Partnership. Also at the municipal level, the Toronto and Region Conservation Authority has been actively supporting energy conservation initiatives. Even in the absence of provincial CDM planning and implementation, some CDM did occur in Ontario.

Toward the late 1990s, Ontario prepared to restructure its electricity system on the basis of a competitive generation market, with CDM left to the market as a response to market price. Shortly after the market opened in 2002, the role of the market was diminished through successive interventions by government. As a result, Ontario now has a hybrid market and regulated electricity system, where the regulated aspect has included contracting for new supply and demand-side resources and the reintroduction of an integrated resource planning framework, with CDM accorded equal treatment with supply resources.

The combination of the government's decision to replace coal-fired generation in Ontario and the growth in summer peak demand has raised even more interest in CDM as a means of dealing with increasing supply inadequacy. The Minister of Energy has, in fact, "jump started" the development of a "conservation culture" in Ontario by setting the goal of a 5% reduction in peak demand by 2007.

Ontario Hydro's 1989 Demand/Supply Plan represented Ontario's first integrated resource plan to cover both demand and supply options. At the time, demand was forecast to grow at 2.2% per annum (before CDM was considered) for the period from 1989 to 2014. Within the demand resources, the plan included efficiency (demand reduction) and load shifting (peak reduction) programs.

As part of the plan, 2,000 MW of efficiency improvements were contemplated for the year 2000, which represented the equivalent of 6.5% of electricity load. Load shifting programs were assumed to contribute an additional 1,000 MW of peak demand savings by the year 2000.

While there was an absence of CDM programs for electricity over the past decade, this was not the case for natural gas programs. In 1993, the OEB established a 'utility model' regulatory framework for the promotion of energy conservation and efficiency by Ontario's natural gas utilities, which expected that the gas utilities would aggressively promote energy conservation

and efficiency. Originally, no link was established between the gas utilities' profits to their success at reducing their customers' energy bills by encouraging higher efficiency.

From 1995 to 1998, Enbridge Gas Distribution (Enbridge) failed to meet its energy conservation targets by 19% to 70%. Starting in 1999, the OEB linked Enbridge's profits to its success in reducing its customers' energy bills through increased energy efficiency. Subsequently, Enbridge exceeded its energy conservation targets by 21% to 67% over the next three fiscal years. As of 2004, CDM programs by two large gas distribution companies in Ontario (Union Gas Limited and Enbridge) had reduced their customers' energy bills by over $1 billion.

CDM measures have recently been reintroduced as a planning priority in Ontario. A request for proposals (RFP) in 2005 was seeking to procure 250 MW of demand-side management and/or demand response initiatives across the province, but with a particular focus on Toronto and west of the GTA. In addition, Ontario's Ministry of Energy authorized LDCs to apply to the OEB for lost revenue adjustment with respect to expenditures on CDM (LRAM – Lost Revenue Adjustment Mechanisms). The goal of such programs is to facilitate more effective implementation of CDM programs by distributors who are closest to the consumer. In the first quarter of 2005, budgets of $20,000 to $39.5 million were approved under the program.

Canada's federal government has been responsible for a number of energy efficiency efforts through its climate change agenda, as part of its commitment to the Kyoto Accord. The federal government offers incentives to commercial and residential sectors for efficiency upgrades through the Canadian Building Incentive Program (CBIP) and the Energy Innovation Initiative (EII). These programs allow applicants to receive up to 25% funding for energy audits and up to 50% for capital upgrades on energy efficiency equipment. The Canadian Industry Programme for Energy Conservation (CIPEC) assists the industrial sector.

Through Natural Resources Canada (NRCan), the Canadian government administers the Energy Star program. The program both delivers information and applies energy labels to major appliances, HVAC products, lighting, signage, consumer electronics, office equipment, windows, doors and commercial and industrial products. Currently there are regulated minimum efficiency levels for over 50 products, and the list is growing.

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3.5 Portfolio Diversification and Risk Analysis

This section describes basic concepts of risk analysis and how they are applied to the current exercise. This includes Monte Carlo (random sampling) simulations, as used in the Portfolio Screening Model and sensitivity analysis.

Risk analysis provides the means for moving beyond analysis of the resource options considered individually to enable analysis of specific groupings of options, i.e. portfolios. As such, risk analysis is a central element of the analysis conducted in the supply mix advice exercise.

3.5.1 Key Findings

- Risk analysis of specific groupings of resource options (portfolios) was a central element of the supply mix advice exercise
- Risk in the electricity sector stems from uncertainties regarding several key factors – fuel price variability and long-term fuel supply, costs and performance of various technologies, generator availability, load growth over time and population and economic factors that influence load, changes in electricity use patterns, and weather impacts
- OPA approached the supply mix exercise from a risk perspective, where risk associated with investments in new supply can be reduced by diversifying generation portfolios
- Risk associated with the various generation portfolios was modeled using the Monte Carlo simulation statistical method which uses sequences of random numbers to simulate what could happen to variables affecting portfolio performance and measuring the resulting distribution of the output parameter (expected cost)
- OPA variables used to run Monte Carlo simulations were fuel prices, load, technology cost, hydro and wind availability, and forced outage rates
- Once the simulations were run for the candidate portfolios, OPA used their respective expected cost and risk (distribution of cost) to compare the portfolios
- Sensitivity analyses were completed to assess portfolio performance given the event of a sudden change in one of the relevant variables

3.5.2 Introduction

Portfolio diversification was a relatively common practice that was never studied in depth until the publication of Harry Markowitz's article on the subject in 1952. Markowitz was able to quantify risk, defined as the standard deviation of returns, and show how diversification into investments that have limited or no positive correlation in their movement can reduce overall risk. In Markowitz's view, correlation is measured by a correlation coefficient which varies

between +1 and -1. Two investments with a correlation of +1 will move in lock-step with one another, while those with a correlation of -1 will move in exactly the opposite direction. Since the correlation coefficient is used to calculate the variance of a portfolio[1], any coefficient less than +1 will reduce the overall variance of that portfolio. While Markowitz developed the principles of portfolio construction based on the relationship between risk and expected return, portfolio diversification to reduce overall risk can also be applied to investments in new electricity supply. The only difference is that expected cost is used as the outcome in place of expected return. Risk in the electricity industry comes from many different sources, including:

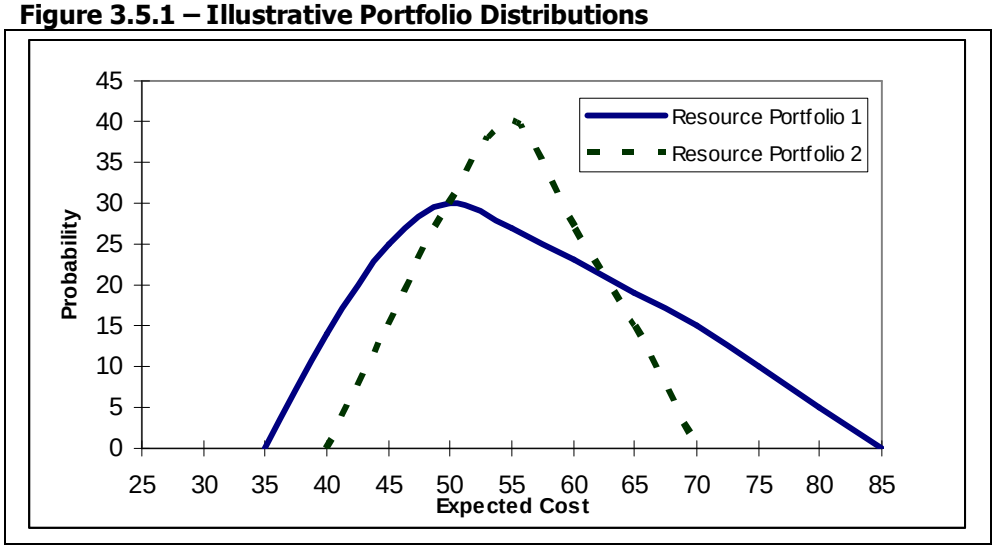
- Fuel – Variability of fuel prices and the uncertainty of long-term supply availability
- Technology – Uncertainty surrounding the cost and performance of various technologies now and in the future
- Generator Availability – Uncertainty on whether generating plants will be available to produce energy when called upon to do so
- Load – Uncertainty associated with load growth over time caused by population growth and growth in the economy and changes in electricity usage
- Weather – Including the impact on water flows for hydroelectric generation and electricity demand

The concept of portfolio diversification is best seen by contrasting portfolios. For example, one portfolio that is heavily weighted toward a particular type of technology might have a relatively low expected cost, but have a greater distribution or high associated risk due to more volatile fuel prices or uncertain capital costs. Another portfolio may have a higher expected cost, but a tighter distribution through increased diversification or reliance on more proven technologies. These two cases are illustrated in Figure 3.5.1.

While it is intuitive that different portfolios of generation assets will have different levels of risk, the question becomes how best to measure that risk to enable robust comparisons of different portfolios.

[1] Portfolio variance for a two-investment portfolio = $x_1^2 \sigma_1^2 + x_2^2 \sigma_2^2 + 2 (x_1 x_2 \rho_{12} \sigma_1 \sigma_2$ where x = % invested, σ = standard deviation, and ρ_{12} = correlation between investment 1 & 2.

Figure 3.5.1 – Illustrative Portfolio Distributions



Source: Navigant

3.5.3 Risk Measurement Techniques

Two of the most popular risk analysis techniques are "Monte Carlo" simulation and "decision tree" analysis. Unfortunately, decision tree analysis does not consider the correlation between variables and is more suitable for situations where each variable has a small number of discrete possibilities. Since Monte Carlo simulation is more appropriate for continuous distributions with long tails and can capture the correlation between variables, the analysis conducted for the supply mix advice focused on Monte Carlo simulation.

3.5.3.1 Monte Carlo Simulation

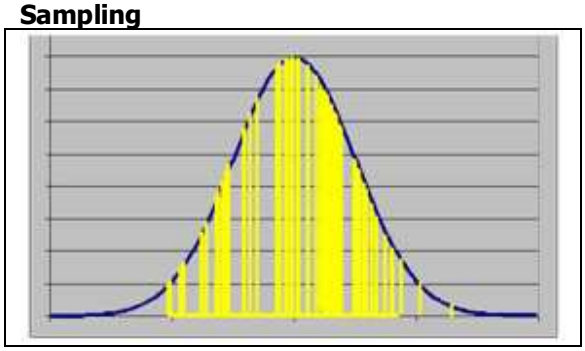
Simulation refers to an analytical method meant to imitate a real-life system. Without the aid of simulation, one would use a deterministic modeling methodology that would not capture the element of risk; that is, it would produce a single outcome, generally the most likely or average scenario. Robust risk analysis seeks to analyze the effects of varying inputs on outputs of the modeled system, which requires the use of numeric simulation methods.

Numerical simulation methods known as Monte Carlo methods can be best described as statistical simulation methods. Statistical simulation is defined here in quite general terms to be any method that utilizes sequences of random numbers to perform the simulation. Monte Carlo is now used routinely in many financial applications and is quite adaptable for analyses which involve the modeling of uncertainty through descriptive variables. A basic assumption underlying the use of Monte Carlo simulations is that the behavior of a system can be described

by functions and variables, and once these are known, the Monte Carlo simulation can proceed by random sampling from the set of descriptive variables.

Assuming that the evolution of the physical system can be described by specific probability density functions and variables, the Monte Carlo simulation can proceed by sampling from this set of variables, which necessitates a fast and effective way to generate random numbers uniformly distributed. The outcomes of these random, or stochastic, samplings are compiled to produce and describe the result. However, the essential characteristic of Monte Carlo is the use of random sampling techniques to arrive at a solution to a physical problem. The output of the simulation is a distribution of values of the output parameter (expected cost), i.e, not just a single line.

Figure 3.5.2—Illustrative Monte Carlo Sampling



Source: Navigant

3.5.3.2 General Parameters Used to Describe Simulation Variables

The parameters used to describe individual variables within the simulation process include time horizon, distribution type, variance methodology, and correlations. (Each of these parameters and how they were used in the Portfolio Screening Model in OPA's Supply Mix Advice are discussed in greater detail in Navigant Consulting's report, Part 4.1).

Time Horizon

Monte Carlo simulation segments the timeframe of parameters into short-term (hourly), mid-term (monthly), and long-term (annual) time intervals for descriptive and modeling purposes. An annual time horizon was assumed for each variable in the simulation process.

Distribution Type

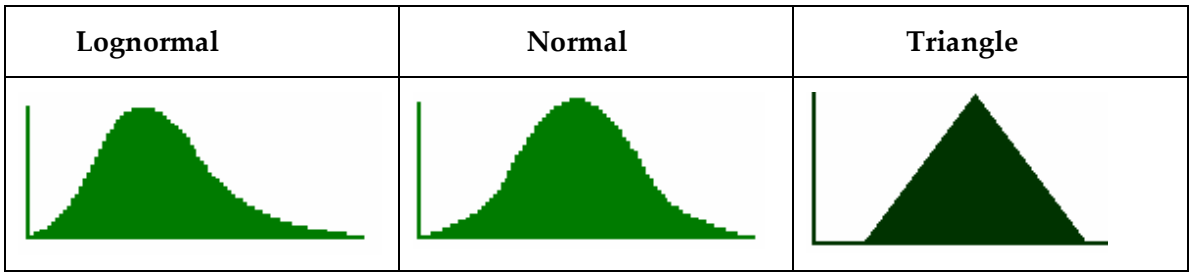
While there are multiple types of distributions that describe data and events, historical analyses of commodity price behavior reflect lognormal distributions of data. Lognormal distributions are observed in situations where values are positively skewed from the mean, but cannot become negative. Commodity prices tend toward lognormal distributions since infrequent but

extreme price spikes create tails that are positively skewed and commodity prices do not fall below a value of zero (for any significant period of time).

Normal distributions are observed in natural phenomena where values are most likely to be clustered around the mean with marginal extreme values occurring equally to the right and left of the mean. The use of normal distributions to describe a variable such as load growth reflect the reality that these estimates can move equally in either direction of their respective mean values.

The following figure illustrates the log normal, normal and triangle distributions.

Figure 3.5.3—Distribution Types



Source: Navigant

The triangle distribution is commonly used where historical data is difficult to obtain in any meaningful quantity. While estimates under a triangle distribution can move in either direction from the mean value, the maximum and minimum endpoints can be estimated reasonably since there are no extreme values expected. The use of triangle distributions is usually an appropriate representation of the behavior for a variable such as capital costs.

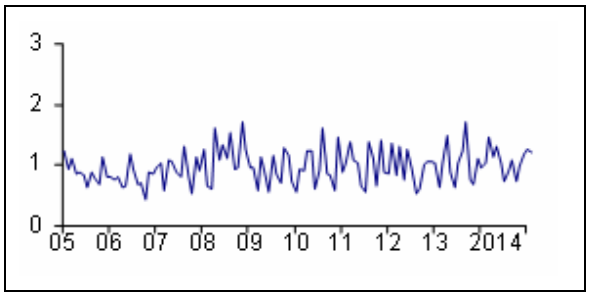
3.5.3.3 Variance Parameter Methods

There are three variance methods that can describe prices: constant variance, random walk, and random walk with mean reversion.

Constant Variance

Constant variance reflects the standard deviation of the mean. For each random iteration, the draw starts at the mean and, as a result, there is no inter-period relationship between iterations. Values tend to fluctuate around the mean in a constant pattern over time, reflecting an equal probability of movement up or down over time, but with no directional tendency. Load growth and interest rate variances are best reflected through constant variance applications. The chart below demonstrates results utilizing a constant variance parameter:

Figure 3.5.4—Constant Variance



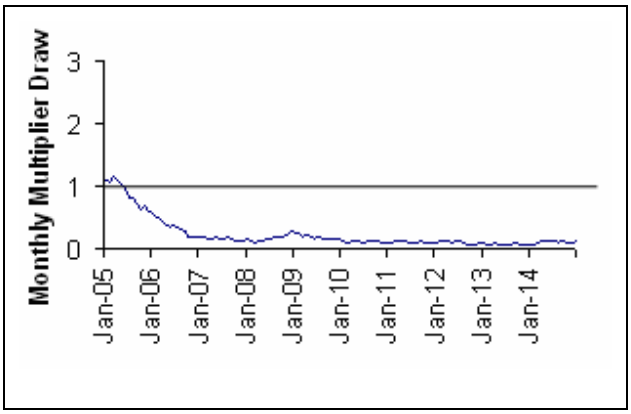
Source: Navigant

Random Walk Variance

Random walk variance reflects the characteristics of Geometric Brownian Motion (GBM), where each iteration in the random draw process begins with the previous period value rather than the mean value. It is appropriate to mathematical modeling of some phenomena in financial markets and is used particularly in the field of option pricing. While this is precisely the nature of stock prices, it does not reflect the nature or historical behaviour of commodity pricing since commodities, at face value, are considered factors of production rather than appreciable assets. As such, the variation of commodity prices through time do not reflect the wide diffusion of variance over time that GBM demonstrates.

The chart below demonstrates results under a random walk variance parameter:

Figure 3.5.5 – Random Walk



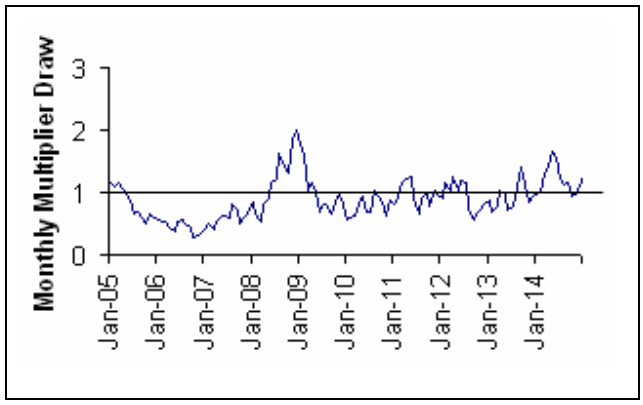
Source: Navigant

Random Walk with Mean Reversion Variance

Random walk with mean reversion reflects a variance parameter that seeks to incorporate the fundamentals of randomly occurring outcomes while staying within the framework of

observable pricing behavior that is consistent with commodity market pricing behavior. The chart below demonstrates results under a random walk with mean reversion variance parameter:

Figure 3.5.6 – Random Walk/Mean Reversion



Source: Navigant

Correlation

In order to conduct a proper Monte Carlo simulation, it is appropriate to account for cross correlations between variables. This ensures, for example, that a high natural gas price draw is not combined with a low oil price draw, but rather is consistent with the historical interaction of the commodities.

3.5.4 Risk Analysis in Ontario Supply Mix Study

For the supply mix advice, OPA constructed a number of portfolios with different technologies employed and varying weights of each technology. After designing the candidate portfolios, their inherent cost was determined using a Portfolio Screening Model. This is a model that performs a simple dispatch of existing and new resources on an hourly basis.

The purpose of dispatch is to decide what units would operate in each hour by selecting those with the lowest variable cost required to supply the demand. In addition to variable cost, each unit has a forecast fixed operating cost plus a return on and of invested capital that must be recovered even if the unit does not dispatch. The total of these costs in any one year represents the revenue requirement for the portfolio. This revenue requirement estimate is performed over the 20-year forecast horizon.

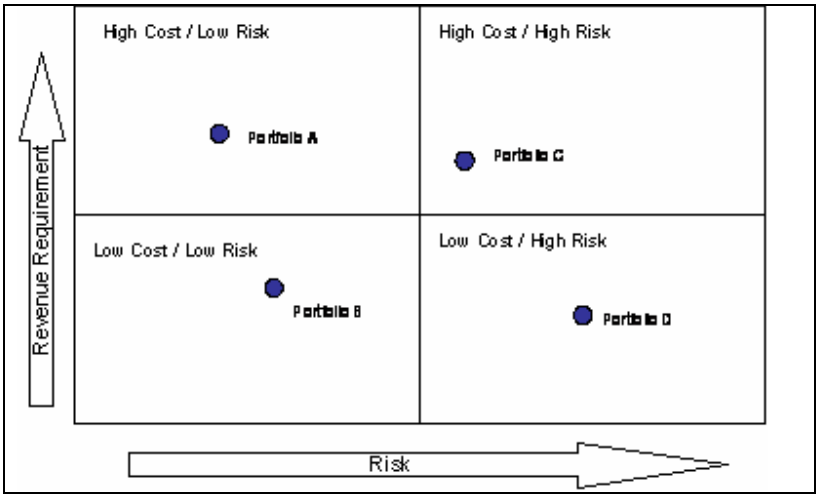
The Portfolio Screening Model was then used to subject the forecasted results to Monte Carlo simulation using the following variables (the distribution type, variance and correlation for each variable are outlined in detail in Navigant Consulting's report):

- Fuel prices rational: gas, oil, coal, uranium
- Load
- Cost of technology
- Hydro and wind availability
- Forced outage rates

A value for each input variable is drawn randomly from the pre-defined distribution and those values are used to perform a simulation of the system. The simulation is repeated 250 times with different draws resulting in a distribution of revenue requirements for each portfolio.

Once Monte Carlo simulations are run for all the candidate portfolios, their results in terms of risk (distribution of revenue requirement) and expected cost are plotted as shown below. This quadrant analysis is a simple but effective method to describe visually how the various portfolios compare from a cost/risk perspective.

Figure 3.5.7 – Portfolio Risk vs Portfolio Cost



Source: Navigant

3.5.4.1 Sensitivity Analysis

Sensitivity analysis is used to assess the impact of a significant change to a key variable upon which the forecast is based. An example would be to evaluate the additional cost of a given portfolio with a long term forecast gas price that is much higher than the base forecast.
An additional analysis was executed to assess the portfolio performance given the event of a significant change in one or a group of relevant variables. In the supply mix study, the following scenarios were considered:

- Climate change: Low hydro availability, broader application of carbon mitigation costs, high wind incentives and low capital costs
- Low gas price
- Technology improvement: high gas price, low capital costs for fuel cells and wind power

The candidate portfolios were simulated for each of these scenarios and the variation in cost with respect to the base case were computed. These resultant variations are an indication of the portfolio robustness.

This type of analysis works best when used to demonstrate how sensitive the results are to changes in a key variable. Since in most "real world" cases there is some correlation between the movement of variables, it must be used with care.

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3.6 Hydroelectric Generation in Ontario

The purpose of this part is, firstly, to outline the technical considerations for planning and developing waterpower in Ontario, secondly, to outline the potential constraints for waterpower development and finally to classify the remaining potential that could be developed within existing public policy guidelines into 5 and 10-year development horizons.

3.6.1 Key Findings

- Ontario's switch from winter to summer peaking has created limitations for hydroelectric facilities having no or limited water storage because summer peaks are sustained over longer periods of time than are winter peaks; moreover, rainfall is at its lowest, and restrictions on water use are at their greatest during the summer
- Waterpower that a "dispatchable" from a control centre is most beneficial to the power system because it can be activated when it is most needed
- Hydroelectric resources are best suited for providing frequency regulation, an essential component in keeping a steady 60 Hz frequency across the province and inadvertent power exchanges with our neighbours to a minimum
- Ontario has 190 potential waterpower sites capable of 7,521 MW but only 1,447 MW could be developed within existing public policy guidelines – another 1,501 MW are inside provincial parks and a further 4,637 MW are subject to agreement with First Nations and the federal government
- Transmission unavailability and the cost of new transmission are the largest impediments to developing potential hydroelectric sites in the northern portions of the province
- Hydroelectric facilities are renewable, sources of electricity that do not consume water
- Hydroelectric installations have three basic types – storage or pondage plants (also known as "peaking" plants), "run-of-the-river" plants and pumped storage plants
- While hydroelectric developments do have some negative environmental impacts, control dams associated with hydroelectric stations have been shown to be effective in mitigating the effects of extreme weather conditions (flood and drought)
- Ontario has close to 200 operating waterpower facilities which account for about 7,700 MW of dependable generating capacity
- Many hydroelectric facilities provide fast-response (or spinning) reserve – power that is available instantaneously and without central control action to respond to emergencies or allowing the flexibility to "load follow" (or adjust to fluctuations in demand)

3.6.2 Introduction

In Ontario, waterpower generation (also called "hydroelectric generation", "hydro generation" or simply "hydro" in this report) accounts for approximately 7,700 MW of dependable generating capacity out of a total of over 30,000 MW of installed generation. In addition, due to rising electricity prices, untapped waterpower sites, whose potential was uneconomic to develop a few years ago, have now become viable options. There is also an increased incentive to maintain and upgrade the existing facilities, thereby ensuring that the potential of these cost-effective, renewable resources is fully utilized.

Where undeveloped sites exist, most have been considered for development at some point in the past. Location and the economics of integrating them in the power system were often the reasons why they were not developed. Transmission unavailability, and the cost of providing new transmission, is perhaps the largest impediment to developing potential hydro sites in the northern portions of the province. In fact, an enabling transmission strategy is needed for optimal development of new hydroelectric sites.

There are, however, other potential constraints that need to be carefully assessed. These potential constraints may be grouped as:

- Social – disruption of peoples' lives or the existing economy – constraints that can be collectively labelled 'citizenship'
- Political – including institutional and legal matters, for example as conflicts with designated use, such as parks and wilderness areas, and
- Environmental – the environmental feasibility at a proposed site or in a resource area that has potential sites.

In such assessments the constraints would be quantified and a determination made of whether further assessment should be conducted and whether the constraints could be mitigated so that a hydro plant could be economically installed and operated. These potential constraints are considered in this section.

While no longer the largest portion of power production around the world, hydroelectric generation is still the most widespread in terms of number of stations. Hydroelectric generation is probably the most difficult type of generating resource to plan for. One of the factors that make it difficult is the fact that it comes in a variety of forms:

- Run-of-the-river (low-head installations)
- Peaking and super-peaking (high-head installations)
- Hydraulically isolated (a single site on a river)
- Tightly coupled stations operating "in cascade" (multiple sites on a river)
- Resources drawing their water from large perennial sources of storage
- Seasonal resources with little or no upstream storage.

What also makes planning for new hydroelectric facilities a little more difficult, in contrast with fossil or nuclear installations, is the fact that fuel supply (water) is subject to a high degree of uncertainty. An important component of operating a waterpower plant is concerned with managing the supply of water to the units of that plant. In fact, other than ensuring that turbo-generators are kept in good working order, managing the operation of that type of installation consists mostly in what is commonly known as Water Resource Management.

3.6.3 Hydroelectricity Fundamentals

Electricity is obtained from water through a process of energy conversion. Essentially, a body of water called a forebay or a reservoir held at an elevated altitude represents an amount of (gravitational) potential energy. By channelling this water down to a lower point in a controlled manner, this potential energy is realized and extracted in the form of mechanical energy by a waterwheel (turbine) located near the lowest point of this water trajectory called the tailrace. A generator attached to the rotating shaft of the waterwheel transforms the mechanical energy into electricity.

Where water is available, hydroelectric power can be a low cost and renewable option. Per unit costs, however, tend to be higher for plants where the elevation difference between the forebay and tailrace are low (known as a "low head" plant) .In addition, costs for transmission add to the cost of developing sites remote from loads. Ontario has very logically already developed the most economical sites (high head, close to load centres) and future developments will therefore be more expensive than past developments were. Compared to other generating technologies, a hydro power plant is simple, reliable, easy to operate and maintain, and usually lasts "forever."

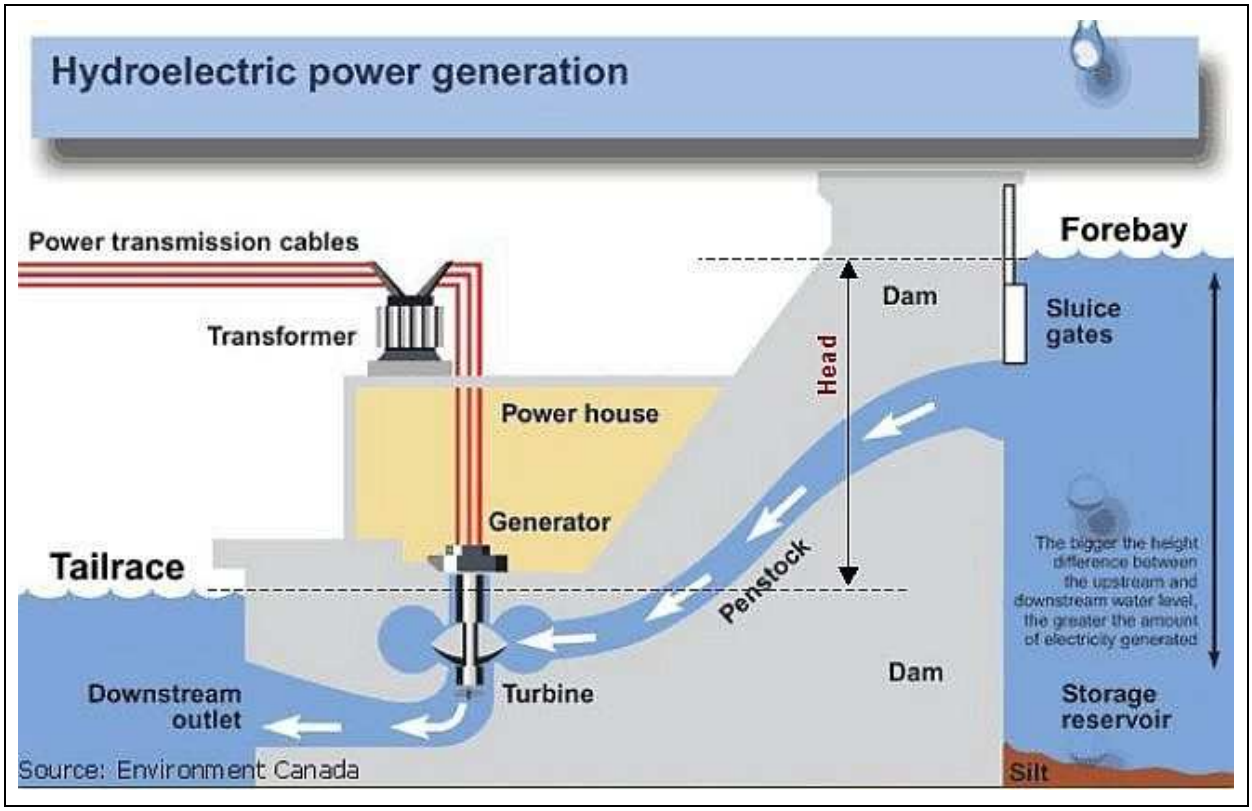
3.6.3.1 Elements of a Hydroelectric Plant

Despite the diversity of forms of waterpower stations, they all include some common elements:

- A significant volume of water that is elevated, usually held in place by a dam
- A penstock (or conduit, or channel) to conduct the water to a lower level
- A turbine (waterwheel) located at the bottom of the penstock and connected to a generator
- A place where the water leaves the turbine (tailrace), and
- Some plant controls and auxiliary apparatus

The following figure shows a typical hydroelectric plant cross section:

Figure 3.6.1 - Typical Hydroelectric Installation (Diagrammatic)



Source: Environment Canada

3.6.3.2 Classes of Hydroelectric Generating Stations

Hydroelectric installations can be classified into three basic types. These are:

- Storage or Pondage plants (sometimes known as "peaking" plants)
- Run-of-the-River plants
- Pumped Storage plants

Some of the characteristics of these types are discussed below.

Storage or Pondage (Peaking) Plants: At many hydroelectric plants, production economics can be enhanced by storing water in the head pond (forebay) for a limited number of hours. This is normally done by partially or completely shutting the plant down (i.e., stopping the water flow) overnight or on weekends, when the demand for electricity is light. The stored water is used

during the peak load period of the following day. This type of operation is called peaking and is carried out routinely on most large power systems.

Peaking power installations are characterized by proportionally large units (in terms of discharge capability) and relatively small forebays (storage capability). They can only sustain continuous generation for a few hours a day before they start running out of water and need additional inflow from upstream reservoirs. Forebays of peaking installations must have large operating ranges, which has impacts on the use and environment of the shoreline of the reservoir. As well, the environment downstream of the plant must be protected against wide fluctuations in discharge flow.

Run-of-the-River Plants: Some plants are not suited to peaking operations because they do not have adequate forebay storage capacity and/or their discharge capacity must match the streamflow of the river they are on. Some examples are plants located on a waterway where shipping interests and other considerations impose restrictions on such peaking operation and where the river flow must be passed on downstream in a more uniform manner.

Run-of-the river installations are usually low-head and their operation, which is often classified as base load, does not follow the economics of supplying the load, but rather the variations of the river flow over time. Water management at this type of installation is often based on established "rule curves".

Pumped Storage Plants: A Pumped storage generating station (PGS) represents a logical complement to load-following operations that are carried out elsewhere on a power system. A PGS time-shifts energy production by storing energy in the form of water. At night, when demand and the cost for power are low, water is diverted from a lower river or lake and is pumped up into a storage reservoir with electric motors. The water is let back down from that reservoir through a set of turbo-generators when the energy is ready to be sold (and used) during periods of high value or need.

Electricity used for the pumping operation is obtained from the system during periods of low demand. This carries an economic penalty in that it takes about 30% more energy to pump the water uphill to the reservoir than can be generated when the time comes to let it back down through the turbines. In addition, there is uncontrolled consumption of that water while it is in the reservoir, through evaporation.

PGS plants are not new. These generating stations are used extensively to time-shift energy production on a daily or weekly basis – away from weekends and into high demand weekday peak hours. One example is the PGS at OPG's Sir Adam Beck complex at Niagara Falls. Another is at the Robert Moses installation across the river in Lewiston, NY. One of the world's largest PGS installations is located at Ludington, Michigan, relatively close to the Ontario-Michigan border. PGS operation is routinely carried out throughout the year and can result in

considerable savings in system production costs, provided that prevailing water conditions and power system economics are favourable.

3.6.3.3 Operating Principles of a Hydroelectric Generating Station

Electricity generated from a hydroelectric installation makes use of a fuel (i.e., water) that is at the same time inexpensive and precious. Water is a renewable resource and its use to generate electrical energy is classified as non-consumptive. This means that other than by occasional small leaks through the various elements of the water passages, any amount of water used to actuate a turbine and produce power is returned to the river system from whence it came.

Waterpower, however, has many other positive traits that make it a very desirable component of the generation complement in a power system. Some of the more salient are:

- A renewable resource that is clean and non-polluting
- A non-consumptive use of water
- Fast response, always at the ready
- Flexible and maneuverable, right from zero output (shutdown) to maximum output (full gate)
- Run of the river is relatively benign environmentally
- Proven, reliable and long-living technology
- Effective in mitigating the effects of extreme weather conditions (flood and drought) which is typically considered of sufficient social benefit to accept the inherent changes made to the natural environment
- Can co-exist with other uses of the water.

Waterpower also has a number of negative traits, especially if corrective actions are not taken:

- Erosion, due mostly to sudden water fluctuations and excessive water velocities, occurs mostly in plant tailraces. It is minimized by well-designed outflow channels that calm the waters quickly and dampen the flow rate before it is delivered to the lower river.
- Impact on fish populations, mostly in the untimely withdrawal of vital waters from spawning beds, and in the prevention of natural fish migrations – it is minimized through careful reservoir and forebay management, ensuring that spawning occurs to completion by keeping water levels high and steady during the critical periods, aiding in the migration by providing alternate routing of the fish (ladders, etc.) during the appropriate times
- Impact on flora (including the cultivation of wild rice in Northern Ontario), and
- Impact on First Nations way of life, including agriculture and water supply.

Waterpower resources that can be controlled from an operating centre – either local or system-wide – are the most beneficial to the power system. They can be activated when it is most economical to do so, or when an emergency occurs. Such resources are said to be dispatchable.

3.6.3.4 Steady-state Operation of a Hydroelectric Generating Station

The two most important parameters in the operation of a waterpower facility are the sustainable water flow through it and the head across it. Head is defined as the level difference between the surface of the plant forebay and the surface of its tailrace.

In order to maximize the power output of a waterpower installation at a given water flow, its head must be kept at or near its maximum. This is usually done by keeping a steady supply of water coming from upstream reservoirs, and doing it in such a way that this supply matches, as nearly as possible, the water being withdrawn from the forebay and conveyed through the turbines. Full forebays usually mean maximum head, which in turn means maximum energy transformation efficiency (usually measured in kilowatts per unit of flow – e.g. kW/m^3).

An inherent characteristic of a hydroelectric turbo-generator unit is that it reaches its maximum efficiency before it reaches its maximum output. Depending on the type of turbine being used and on the configuration of the water passages, maximum efficiency may be reached anywhere between 85% and 97% of the maximum flow that can be passed by the turbine. The operating point at which maximum efficiency is reached is known as the Best Efficiency Point (BEP) and this desirable operating mode is usually labeled "efficiency gate" operation.

Unless water is so plentiful that it exceeds the amount required for efficiency gate operation, and spill (i.e. waste) becomes the only recourse left for the operator, waterpower units are operated at or near their BEP a large portion of their operating hours.

That inherent characteristic of waterpower units also accounts for a very important function in their operation. That is the provision of operating reserve. The 'idle margin' between output at Best Efficiency and output at maximum flow (so-called Full Gate output) is considered by the system operator to be fast-response (or spinning) reserve that is available instantaneously and automatically without operator intervention when there is a system emergency such as the unexpected automatic shutdown of another generator somewhere on the system.

During periods of very high flows, such as during the spring freshet (the period in the spring when water is in abundance because of snow melt and rainfall), water is utilized in the units rather than spilled and wasted. Operating hydro units beyond their Best Efficiency Point still produces additional energy (MWh), albeit at a lower efficiency. This, in effect, is a case of "use it or lose it". It should be noted, however, that prolonged full-gate operation of a hydroelectric installation can cause a head loss and a decrease in station capacity (MW) due to a rise in the tailrace level.

Finally, while a unit carries its maximum capacity on its nameplate, once the unit is loaded to its nominal capacity, it can only sustain that output level if the supply of water is maintained. Output sustainability is a crucial requirement of current and future waterpower installations.

3.6.3.5 Dynamic Operation of a Hydroelectric Generating Station

In a power system such as Ontario's, where the daily generation mix includes units of differing flexibility, waterpower is of great benefit because of its flexibility and fast response rate. Hydroelectric units can be loaded quickly and reliably during periods of load pickup (morning, sudden changes in generating conditions) and unloaded just as quickly when load drops in the evening hours.

At most peaking stations, individual forebays are of limited volume. In years past, the Peak Capacity rating of a hydroelectric station was based on the station's ability to meet a two-hour uninterrupted period of high demand once a day, for five consecutive days. Even then, in order to avoid costly head losses, peaking operations had to be coordinated with releases from upstream reservoirs. And finally, in order to be rated with a great deal of assurance/certainty, the peak capacity of a station would be one which could be attained 98 times out of 100, or under what is known as "dependable" conditions.

Current reality is different. Ontario is now a summer-peaking system, with highest demand being reached during the hot humid days of summer. Under summer peaking operation Peak Capacity must be redefined from that of meeting demand for two hours per day, to the meeting and supplying periods of high loads that can last 10 or 12 hours each and every day. Because they result primarily from air conditioning which inherently runs for many hours in a typical day, summer peaks are more like energy peaks, where sustainability of supply is paramount.

Sustainability must recognize in particular that typical hydroelectric stations cannot operate for such long periods by simply utilizing the water contained in their forebays, that is, under these conditions there must be withdrawals of water from upstream storage sources if a high output level is to be maintained.

Unfortunately for the power generator, summer is the season when level fluctuations in provincial lakes is at best constrained, or in some cases not allowed at all. These limitiations reflect both increased recreational use of lakes and waterways as well as the reduced ability of lake levels to recover due to lower seasonal precipitation levels in summer. Draw-down of most lakes is usually no permitted, and natural inflows (through rain) are at their lowest point. This is equivalent to saying that the fuel supply to these hydroelectric installations has become inadequate, leading to limitations to these facilities when they are most needed.

Last but not least, an important feature of hydroelectric resources is their ability to "load-follow". This feature, linked to the resource's inherent operating flexibility, enables automatic control systems to be applied to hydro generators (Automatic Generation Control or AGC) to continually adjust a station's power output to follow the minute-by-minute fluctuations of the provincial demand for electricity. Umbrella organizations or 'pools' of interconnected utilities, and standard-setting bodies like NERC and NPCC, specify the amount and type of AGC that must be 'carried' by the system.

Errors in AGC operations are mostly due to the slow response of resources assigned to that task. Such errors cause fluctuations in system frequency (above or below 60Hz) and lead to inadvertent power exchanges with neighbouring utilities. Thanks to its hydroelectric resources, Ontario has been able to achieve exemplary results over the years and must continue to do so in order to continue to be allowed to interconnect with its neighbouring electricity systems.

Under normal conditions, the bulk of Ontario's AGC is carried by the Niagara River installations at the Sir Adam Beck GS.

3.6.4 Applied Water Resource Management

Every power system operator who has responsibility for the operation of hydroelectric resources is a de-facto water resource manager. For the operator, what is important about managing this 'fuel' is in the following short list:

- How much precipitation will fall, where, and when?
- Of that precipitation, how much can be collected and stored?
- Of the rest of the precipitation, how much will end up in rivers and lakes feeding the station?
- Can this water be used without impacting nature or other water users?

The answer to the first question is, "One does not know, for sure". However, two separate fields of endeavour help the operator make an educated guess. These fields are meteorology and hydrometric analysis. The answer to the second question lies in the design of the water retention facilities and of the interconnecting water conveyances. The answer to the third is provided by a sub-field of water resource management: inflow forecasting. The answer to the final question varies from location to location, but can generally be summarized under the headings of care for the environment and of consideration of others.

Meteorology is the science concerned with predicting the weather. It is an important science that services various industries, from agriculture to air navigation. Meteorology deals routinely with laws of probabilities. Based on the observation of weather patterns around the world, on atmospheric and stratospheric currents, on barometric patterns (the high pressures and the low pressure fronts), and on various other variables now supplied to them by satellites, meteorologists are able to make plausible predictions extending to almost one week.

Meteorology is a short-term science: by the time a meteorologist looks beyond four days in the future, the probability of the predictions coming true is only 50%.

At this point, the notion of timeframe becomes important. The short-term is generally accepted to be the horizon of five days ahead, any horizon beyond the five-day limit and up to a year is called mid-term, and anything beyond that is called long-term.
System operators such as the IESO and OPG are usually most concerned about the short and mid terms. For the job of managing their hydro resources to be effective, the operators need to know what to expect in terms of water, both now and beyond the five-day-ahead time horizon. For that, they need to rely on a branch of hydrology known as inflow forecasting.

System planners such as the OPA, on the other hand, are mostly concerned with the longer term in order to properly design and size a prospective hydroelectric station. Climatology, or the science concerned with the study of climates, gives some clues on what to expect "in general, in the long term". It tries to forecast when the rainy and dry seasons are, it tells when and where to expect snow – and it does that by detecting patterns in the historical record. But again, it does not precisely predict deliveries of water in any given timeframe. It only gives indication of what to expect under 'normal' conditions.

Floods and droughts are what hydrologists call "extreme events". Both involve the sustained abundance of or lack of precipitation and cannot be predicted with any degree of precision as to when they will occur or how severe they will be. Factors like global warming or the incidence of "El Niño" are some of the components that are being taken into consideration in modern climatology.

3.6.4.1 Forebay and Reservoir Management

Ontario climatologists have often summarized the vagaries of inflow forecasting by a few simple rules-of-thumb:

- Ontario exhibits a modified continental weather pattern: long, cold winters, in opposition to hot, humid summers, and brief intermediate seasons (spring and fall) with wet conditions and temperate environmental conditions
- Southern Ontario lakes and rivers (south of the 50th parallel) get 60% of their natural inflows over a six-week period in the spring, when the "freshet" period combines snowmelt with periods of abundant rainfall
- Fall is usually a wet season, when flooding is most likely
- Evaporation is the single largest uncontrolled factor in the management of water resources. It is known that in a 'normal' year, evaporation from the surface of the Great Lakes is comparable in magnitude to the flow over Niagara Falls
- Summer is the time when lakes and rivers are at their maximum usage levels by navigation operators, tourism, sporting events, anglers and fishermen, etc.
- Extreme events are bad for the environment as well as for the affected populations. Flooding can cause severe property damage and loss of life, and drought can affect drinking water quality, and sewage treatment and disposal

With these rules in mind, water resource managers – including hyroelectric operators – manage Ontario's lakes and rivers in such a way as to maximize their economic value while minimizing the negative effect of their management on the environment.

Some of Ontario's resources, such as those at Niagara and on the St. Lawrence, are run-of-the-river. By and large, they operate 24 hours a day, 7 days a week, and their level of output depends wholly on the prevailing water flows. Any water that is allocated for power generation but is not used at these installations is effectively spilled, becoming a last resource.

In the daily dispatch of generating resources, run-of-the-river hydroelectric resources are scheduled first, along with the province's nuclear units. No management of these resources beyond the application of static flow-to-time-of-year relationships (called Rule Curves) is done.

Run-of-the-river hydroelectric stations are least useful in terms of operating flexibility and peak load-meeting capability. They are also least useful in mitigating extreme conditions since they have to pass whatever flow they receive, as they receive it, either under flood or drought conditions. But of course they are nevertheless still useful in terms of energy production.

Dispatchable peaking hydroelectric stations, on the other hand, are among the most flexible resources in the power system:

- They are always available
- They can be scheduled (respond to operators' orders)
- They can ramp up or down very rapidly
- They make maximum use of the available hydro potential and return all the water they use to their original river
- They are beneficial in controlling the effects of extreme conditions
- Their negative impact on the environment can be mitigated (see below)
- They can co-exist with other industries and uses of the water

For hydroelectric resources to be used at their maximum potential, judicious reservoir management is necessary. At its most rudimentary, sound reservoir management consists in:

- Maximizing plant head by keeping plant forebays at or near the top
- Drawing all reservoirs (and forebays) down to their lowest operating levels just before the start of freshet
- Keeping lake levels steady and high during the summer (tourist season)
- Lowering lake levels a little at the end of summer in order to receive fall rains
- Exercising care during spawning season so as to not adversely affect fish populations
- Accommodating other users of the affected river system in accordance with established rules.

3.6.5 Hydroelectric Potential in Ontario

3.6.5.1 General Factors

The province of Ontario has close to 200 operating waterpower facilities, geographically distributed across the province. When hydropower development began a century or so ago, these sites were generally the most economic to develop. Figure 3.6.2 provides a map of the existing waterpower sites in Ontario.

The potential for future development lies in sites which are generally more difficult and expensive to develop due to a number of limiting factors. Figure 3.6.3 provides a map of the potential waterpower sites in Ontario. The factors that must be considered for development to take place can be grouped as follows:

- Natural factors of the site, including the possible head, the available water and its variability across the seasons, and its geotechnical factors such as soil and rock conditions
- Business aspects of the would-be project, including site ownership
- Availability of transmission and distribution facilities
- Environmental and citizenship constraints related to potential impact that a hydroelectric project at a given site would have on the environment and on other users of the water, and
- Impediments to development caused by provincial and federal government policies.

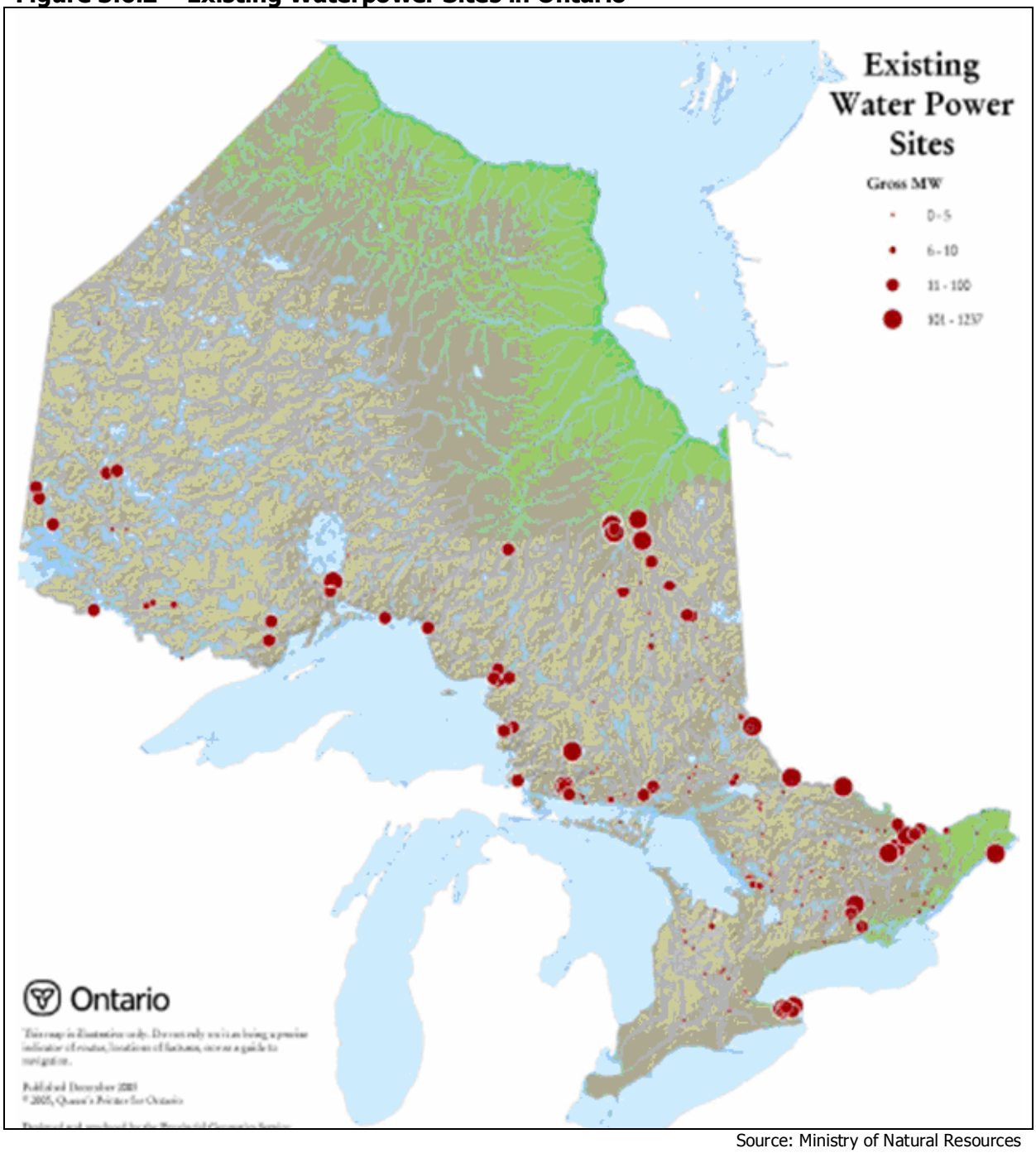
In addition, the practical consideration of the various steps that would constitute the development project for a site introduces the notion of "minimum time factor" that must be considered when estimating the timing of capacity additions. It is not realistic to assume that all potential could be realized at the same time. For this reason, a very coarse timeline was considered in this exercise to estimate how much capacity could be available within 5 years, 10 years and 20 years (and beyond).

Natural Factors

Natural factors are the first consideration to be studied when estimating the potential of a site. Without an adequate head (elevation differential), a substantial and sustained water flow, and a good geological base, a potential site will not be economic.

Of all the undeveloped sites included in this inventory, very few have undergone a formal analysis of their natural factors. Most data, especially for the northern sites, has been estimated from topographical information gathered over many years by government and crown agencies such as Ontario Hydro. Since 2004, the Ministry of Natural Resources (MNR) has used a digital elevation model (DEM) to update some of the available information. However, estimates of capacity and energy production potential are still very approximate.

Figure 3.6.2 – Existing Waterpower Sites in Ontario



Source: Ministry of Natural Resources

Business Aspects

Ownership of the land that contains a potential hydroelectric site is a major factor in its inclusion in an inventory of future resources. The following are some considerations:

- The largest portion of these sites is on Crown Land and subject to MNR Site Development Policy (see policy comments below)
- A number of sites, mostly small ones, are on private property
- A small portion of the remaining potential is under the control of the Federal Government
- Local citizenship aspects of a hydroelectric development allowances must be made to minimize the encroachment of a hydroelectric installation upon other interests along the affected river systems ("riparian" interests)

Availability of Transmission

The integration of new hydroelectric resources into the power system depends on the availability of suitable transmission facilities. While large generating centres (e.g. Mattagami River plants) can be integrated directly into the bulk power system, small hydro projects depend on the availability of smaller connection points on the distribution system.

Besides the difficulties inherent to developing hydroelectric resources in a remote location, the economics of integrating some of the most promising sites into the power system were most often the reasons why they were not developed originally. Today transmission unavailability remains a significant impediment to developing potential hydro sites in the northern portions of the province.

Hydro One Networks' forecast of planned facilities for the next 10 years shows very few new lines and stations north of Lake Superior and in the north eastern part of the province. For purposes of this inventory, availability of transmission and distribution for small sites has been used as a filter, but in determining the timing of some of the committed facilities, the study chooses to err on the optimistic side, and assume that it would not come in the way of the development of the most desirable sites, over the next 10 years. Since OPA's first Integrated Power System Plan (IPSP) will benefit from a decision on the preferred supply mix where Hydro One Networks' plans could not, it will be able to include appropriate transmission facilities insofar as hydroelectric development is a feature of the preferred supply mix.

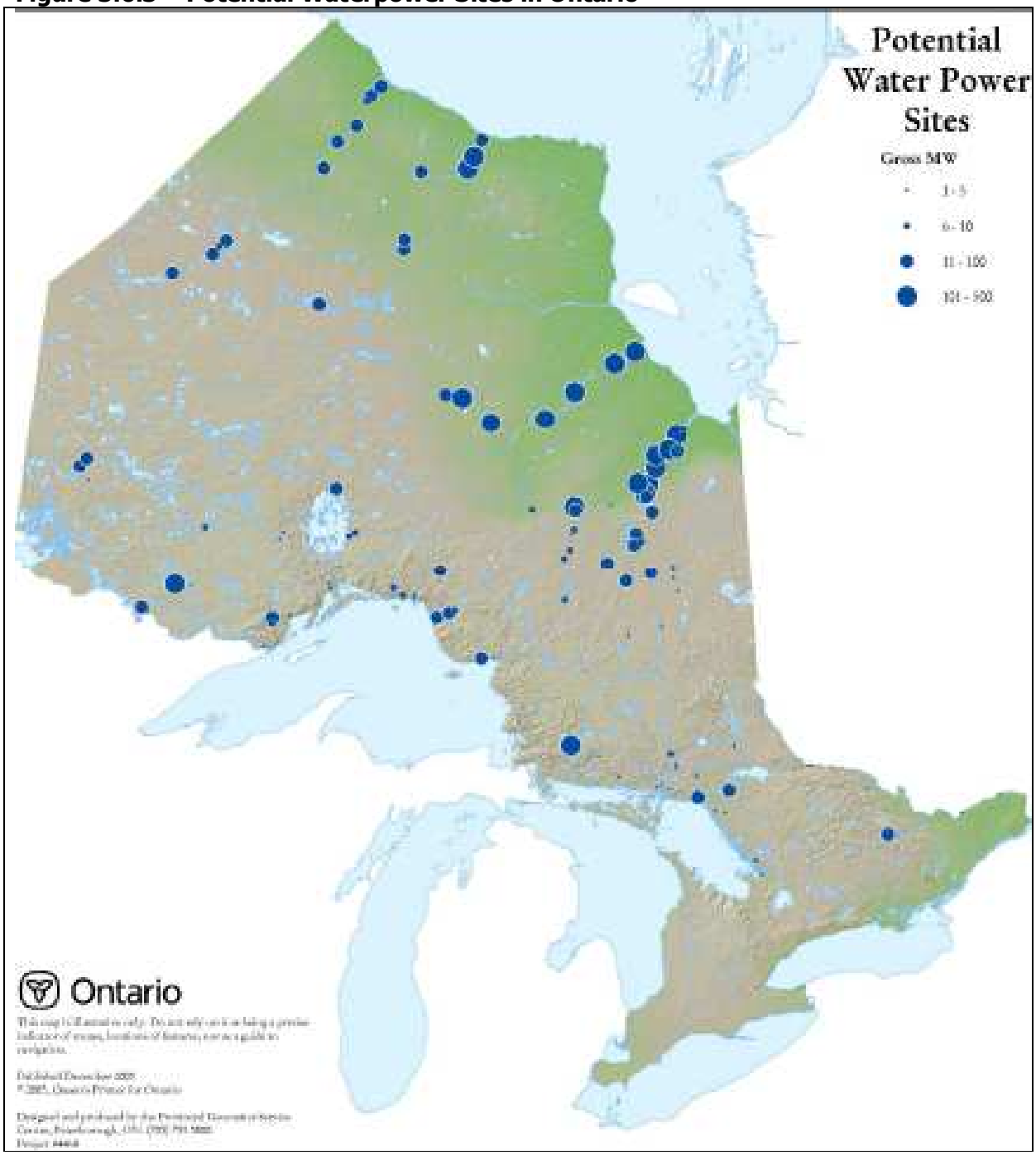
Citizenship Constraints

Citizenship constraints include making allowances for such uses as:

- Commercial and recreational navigation
- Hunting and fishing
- Water supply to towns for drinking and pollution dilution

- Sporting events
- Tourism industry – in all its forms

Figure 3.6.3 – Potential Waterpower Sites in Ontario



Source: Ministry of Natural Resources

Public Policy Constraints

Public policy, including an array of legislation, regulations, policies, and Ministerial commitments, enacted and made by the federal and provincial governments over time, and the collective effect of how these interact, will have a major influence in determining how much of Ontario's remaining waterpower potential can be realized. This includes:

Legislation: All hydro developments in Ontario are subject to environmental assessment (EA) and other pre-development reviews and approvals. An array of federal statutes, such as the Fisheries, Navigable Waters Protection, and Species at Risk Acts, as well provincial statutes, such as the Ontario Water Resources, Lakes and Rivers Improvement, Public Lands, Planning and Ontario Energy Board Acts, are automatically or frequently triggered by proposed hydro developments.

Applying the provisions of these statutes, and supporting policies, will preclude hydro development from occurring in some instances. The necessary process of balancing the local social, environmental and economic interests affected by hydro projects with the provincial interest in power generation also means that a portion hydraulic energy potential of a number of sites cannot be realized. Transmission system and distribution system codes also have an important role to play in determining whether it is economic to connect various areas of this province with renewable energy potential, such as hydro. The combined array of these requirements, in and of themselves, can also form a barrier to investment in hydro development.

On October 25, 2005, the government introduced Bill 11 (proposed amendments to the Provincial Parks Act) in the Legislative Assembly. The Bill, if enacted, would prohibit new hydro development in provincial parks and conservation reserves, subject to certain exceptions. In essence, these amendments will codify in law current provincial policy on “permitted uses” in provincial parks and conservation reserves. Under the Bill, current hydro facilities could continue to operate, be maintained and, with the approval of the Minister of Natural Resources, may be improved.

As well, subject to the Minister’s approval, hydro developments arising from commitments in existing land use plans, and developments in which the electricity would be for use within a provincial park or protected area would be permitted. Unlike the current “permitted uses” policy, and with the approval of the Lieutenant Governor in Council, new developments would be permitted in provincial parks and conservation reserves to serve communities not connected to the IESO-controlled grid (“off grid” communities). Under the Bill, the government, subject to the approval of the Legislative Assembly and the Lieutenant Governor in Council, would continue to have the option of being able to deregulate a portion of a provincial park or conservation reserve to permit hydro development.

Parks and Protected Areas: This includes lands in regulated national and provincial parks, and provincial conservation reserves. In the late 1990s, as part of efforts to complete Ontario's system of parks and protected areas, MNR led an extensive Crown land-use planning exercise known as "Lands for Life." This process culminated in government decisions to greatly expand the system of provincial parks and protected areas. The area in waterway parks was increased by 175%, and includes some sites with significant hydraulic energy potential.

Existing Commitments: MNR's current Waterpower Site Release and Development Review policy, which outlines how the province will facilitate access to new waterpower opportunities, identifies two key "policy areas": the "Northern Rivers" and that part of the Moose River basin which is north of Highway #11. These policy areas reflect government commitments that were made to First Nation communities in the early 1990s, when Ontario Hydro was preparing its Demand/Supply Plan. These commitments have been reconfirmed by each subsequent provincial government, including the current government.

a) **Northern Rivers Commitment:** This commitment sets out that there will be no development greater than 25 MW in the basins of the Albany, Attawapiskat and Winisk Rivers; development less that 25MW can proceed if it is proposed by the local Aboriginal community or communities and/or their partner(s). This commitment was made by a Minister of the Crown in response to community concerns about the potential for extensive flooding associated with hydro development. In the interest of treating all the northern rivers in consistent manner, the Severn River was added to this commitment at the time the Waterpower Site Release and Development Review policy was approved in 2004.

b) **Moose River Basin Commitment:** This commitment, which was made at the same time as the Northern Rivers commitment, pertains to new development (Greenfield or redevelopment) within the Moose River basin, north of Highway 11. Ontario committed that there would be no hydro development, other than the "extension" to the generating capacity of four existing (now) Ontario Power Generation-owned facilities located along the Mattagami River (as set out in an environmental assessment approval) until such time as a co-planning process is developed, agreed to and applied by the affected First Nations and Ontario.

While the Northern Rivers and Moose River Basin commitments were never enacted in legislation (as with most public policy decisions), as these commitments were made by a Minister of the Crown and reconfirmed by successive governments, it would be prudent at this time to clarify the necessary steps to move forward on meeting the Moose River Basin commitments.

3.6.5.2 Development Potential and Constraints

This section presents analysis on potential hydroelectric resources according to proximity to transmission and distribution (i.e. connections), as well as constraints regarding parks policy or agreements with First Nations. After allowance for these constraints, the potential is further reduced by considering only sites which could be developed within the timeframe of this supply mix advice. This potential in turn is divided into portions deemed suitable for development within 5 and 10-year horizons.

Ontario's total potential of 7,521 MW is shown in the following table.

Table 3.6.1 – Ontario's Hydroelectric Potential by Site Size and Transmission Proximity

Transmission Proximity of Site	Under 1 MW (50 sites)	1 - 5 MW (47 sites)	5-10 MW (22 sites)	10-100 MW (46 sites)	Above 100 MW (25 sites)	Total Potential*
Within 5 km		55	35	348	1,287	1,725
5-25 km		35	75	385	826	1,321
Beyond 25 km		59	57	864	3,465	4,445
TOTAL:	**30**	**149**	**167**	**1,597**	**5,578**	**7,521**

Source: OPA, MNR

*Includes both new sites and improvements to existing sites

Sites in Parks and Protected Areas

As described previously, lands classed as parks and protected areas, which include national/provincial parks and conservation reserves, are precluded from hydroelectric development by blanket policy prescriptions.

The precluded potential sites located in parks and other protected areas include new generation:

- On the English River (3 sites, + 68 MW)
- At Patten Post on the Mississagi River (+250 MW)
- On the Missinabi River (+215 MW)
- On the Madawaska River (+94 MW) and the Northern Rivers of the province (+100 MW)

The following table shows the breakdown of these sites in relation to the total potential.

Table 3.6.2 – Hydroelectric Potential Within Parks (MW)

Transmission Proximity of Site	Total Potential (MW)	Within Provincial Parks				Total Potential Within Parks MW)	Total Potential Net of Parks (MW)
		1-5 MW (1 site)	5-10 MW (7 sites)	10-100 MW (17 sites)	Above 100 MW (5 sites)		
Within 5 km	1,725	8	0	0	0	8	1,717
5-25 km	1,321	18	18	235	390	661	660
Beyond 25 km	4,445	12	37	375	408	832	3,613
TOTAL:	**7,521**	**38**	**55**	**610**	**798**	**1,501**	**6,020**

Source: OPA, MNR

Sites Subject to Existing Commitments

This grouping includes some of the most promising sites left in the province. It includes the northern rivers commitment as well as the Moose River Basin commitments. The specific commitments are outlined above and result in the following constraints to development:

- Abitibi River (6 sites, + 905 MW)
- Albany River (10 sites, +2400 MW)
- Mattagami River (3 sites, +223 MW)
- Severn River (14 sites, + 726 MW)
- Winisk River (7 sites, + 485 MW)

The impact of removing these sites from consideration is given in the following table.

Table 3.6.3 – Hydroelectric Potential Subject to Agreements (MW)

Transmission Proximity of Site	Total Potential Net of Parks (MW)	Subject to Agreements				Total Potential Subject to Agreements (MW)	Total Potential Net of Agreements (MW)
		1-5 MW (8 sites)	5-10 MW (3 sites)	10-100 MW (21 sites)	Above 100 MW (18 sites)		
Within 5 km	1,717	12	7	27	627	673	1044
5-25 km	660	0	16	82	436	534	126
Beyond 25 km	3,613	8	0	302	3,056	3,366	247
TOTAL:	**6,020**	**20**	**23**	**411**	**4,119**	**4,573**	**1,447**

Source: OPA, MNR

Potential Remaining for Development

The remaining total of 1,447 MW includes 3 sites on the little Jackfish River (162 MW) and 330 MW from sites rated at less than 1 MW.

The breakdown of this 1,447 MW that is not restricted by technical, economic or policy guidelines is shown in the following table.

Table 3.6.4 - Hydroelectric Potential within Policy Guidelines by Site Size and Transmission Proximity (MW)

Transmission Proximity of Site	Under 1 MW (50 sites)	1– 5 MW (28 sites)	5-10 MW (12 sites)	10-100 MW (7 sites)	Above 100 MW (2 sites)	Total
Within 5 km		39	33	311	660	1,043
5-25 km		17	41	69	0	127
Beyond 25 km		40	20	187	0	247
Total:	**30**	**96**	**94**	**567**	**660**	**1,447**

Source: OPA, MNR

The total of 1447 MW does not eliminate sites on the basis of proximity to a transmission or distribution connection point. About two-thirds of the 1447 MW is within 5 km of the nearest connection point. However, it may not be economic to develop all of this potential, for example, some or all of the 40 MW from 1-5 MW sites that are located more than 25 km from a connection point.

The total of 1447 MW includes;

- 500 MW of pumped storage
- 385 MW of plant upgrades and extensions, and
- 562 MW at new sites, including 3 sites on the little Jackfish River (162 MW) and 30 MW from sites rated at less than 1 MW.

Planning Horizons

The total of 1447 MW has been grouped onto two time horizons: 5-year and 10-year.

5-year Horizon (2010)

The 5-year planning horizon is meant to include upgrades of existing facilities, small new build facilities, and new facilities, where the projects are either under construction or firmly committed to, or, in the case of OPG facilities, where final provincial government approval can be reasonably anticipated: :

- Beck Tunnel (about +50 MW)
- Mattagami turbine upgrades (+34 MW)
- Mattagami plant extensions and the full redevelopment of Smoky Falls GS (+357 MW)
- Turbine upgrade at Abitibi Canyon GS (+30 MW)
- Turbine upgrades at Cameron Falls and Alexander GS (Nipigon River) and at Caribou Falls GS (English River.) – (Total: +10 MW)
- Turbine upgrade at Mountain Chute GS (Madawaska R.) (+4 MW)
- New generation on the Trent and Rideau rivers/canals (+17 MW)
- New generation in northeastern Ontario – 12 sites, all small hydro (115 MW)

10-year Horizon (2015)

The mid-term planning horizon of 10 years includes additional facilities that are in the commitment process but are experiencing an indeterminate delay, or for which MNR has selected or is in the process of selecting an Applicant of Record (AoR). Specifically, these additions are :

- New generation on the Little Jackfish River - 3 sites, to be developed as a single 'reach' – (+162 MW) – Constraint: Transmission.
- New generation on the Namakan River – 2 sites – (+18 MW)
- New generation on the Namewaminikan River – 2 sites, to be developed as a 'reach' – (+8 MW)
- A pumped generating station at Steep Rock Mines (Seine River) – (+500 MW)
- Private, small hydro development on various north eastern Ontario rivers – 8 sites - (+37 MW)

3.6.5.3 Remarks on Specific Sites and River Systems

The following remarks are specific to particular existing or future potential sites, grouped by river.

Niagara – St. Lawrence River

Sir Adam Beck GSs

The Sir Adam Beck II Generating Station has recently undergone a rehabilitation program that increased its peak capacity slightly. Tests are still ongoing to more accurately determine this increase in efficiency.

The Sir Adam Beck I GS continues to supply a portion of its output at 25 Hz, to Stelco in Hamilton. This load, around 25MW, will remain active for the foreseeable future. A single frequency changer unit remains in service.

A new tunnel is now under construction under the City of Niagara Falls, to supplement existing tunnels and channels. By making use of Canadian water previously used by now retired generating stations, this new tunnel is expected to add in the order of 750 GWh of energy production per year. Operating dynamics after the addition of the new tunnel will cause a marginal improvement in total plant capacity (about 5 MW) due to increased dynamic head.

Pumped Generating Station

A very useful part of the Niagara complex is the station's ability to provide supplementary peak capacity to the complex at times of high electricity prices. Being a PGS, it is in fact a net load to the system. It consumes about 30% more energy during its pumping cycle than it can produce during its generating hours. The use of the PGS depends on the prevailing economics of operating the power system.

R. H. Saunders GS

Strictly a run-of-the river generating station, Saunders is run according to fixed criteria set by the International St. Lawrence Board of Control. These are embodied in a set of "Rule Curves" and a number of supplementary regulations to cover unusual or extreme circumstances.

Ottawa River and Tributaries

No new facilities are planned for the main stem of the Ottawa River. There is, however, a sizeable untapped potential in extensions to existing facilities (e.g. Chats Falls) and in new facilities.

The Ottawa River is a tributary to the St. Lawrence River, with the confluence located just upstream (west) of Montreal. The combined flow of the two rivers surrounds the island of Montreal and can on occasion cause serious flooding in that city. For that reason, and especially during high flows, the operation of facilities on that river is overseen by the Ottawa River Regulation Planning Board and its Regulating Committee.

Stations on this river draw their energy from Lake Timiskaming, its main upper reservoir. Variations in lake levels are subject to strict controls in order to accommodate its multiple uses and affected parties along its shoreline.

Possible extensions to the Ottawa River plants were considered but deemed impractical at the time of the preparation of Ontario Hydro's Demand/Supply Plan. This potential for new capacity should warrant some consideration in the near future.

Chaudiere Falls GS (Hydro Ottawa) has recently undergone a complete rehabilitation program.

Misema GS (on the Misema River) is a new small hydroelectric installation operated by the Canadian Energy Corporation. It is rated at about 4 MW.

Madawaska River

This is a prime peaking river. It draws energy from Bark Lake (Palmer Rapids), a power reservoir subject to strict environmental and citizenship limits. Mountain Chute GS is undergoing a rehabilitation program, including a turbine upgrade. This work should add about 4 MW to the total station peak capacity rating.

3.6.5.4 Current Site Development Process

The majority of promising hydroelectric sites are situated on Crown Land, and as such are under the control of the Ministry of Natural Resources. A number of these sites have been identified by the Ministry and released to a competitive bidding process.

In three separate Requests for Proposals (RFPs), a number of sites covering a range of sizes and diverse locations around the province were specifically identified, and the public at large was invited to bid by submitting Expressions of Interest to the Ministry.

- These expressions of interest would be followed by suitable pre-feasibility studies and summary business plans, and where appropriate, meeting and negotiating with First Nations representatives.

Each submission would then be assessed by Ministry staff against established criteria covering engineering, economics, social and environmental aspects.

The outcome of this assessment will be the awarding of the site (for development and exploitation) to one of the applicants, making it the "Applicant of Record" (AOR).

The AOR then needs to commit to the project (i.e. start the Full Feasibility and Environmental Assessment processes within a specific number of months) and proceed through a number of steps leading to the design and construction of the new facility.

These steps include, but are not limited to:
- Preparing a WMP
- Arranging for a connection to the grid
- Meeting with ratepayer groups and municipalities
- Investigating possible citizenship impact, including the securing of tentative agreements with other users of the water

3.6.6 Appendix 1: Listing of Sites

Table 3.6.5 lists the new sites included in the total potential of 1,447 MW that are within guidelines.

Table 3.6.5 - Hydroelectric Potential within Policy Guidelines: New Sites

Site	Potential (MW)	Connection Distance (km)	Cons-traint*
Abitibi River			
Sextent Rapids	16.14	< 5	A
Allan Rapids	131	5 - 25	A
Sand Rapids	131	5 - 25	A
Black Smith Rapids	140	< 5	A
Coral Rapids	192	< 5	A
Nine Mile Rapids	295.20	< 5	A
Aguasabon River			
Lower Lake	9.80	5 - 25	
25.6 - 19.2 km from mouth	10	< 5	
Albany River			
Lower Limestone Rapids	10.37	> 25	A
Achapi Lake	15.75	> 25	A
Miminiaka Lake	15.83	> 25	A
Buffaloskin	76	> 25	A
Wabimeig Creek	185	> 25	A
Stooping	285	> 25	A
Chard	370	> 25	A
Biglow	480	> 25	A
Blackbear Island	490	> 25	A
Hat Island	490	> 25	A
Arrow River			
High Falls	1.18	> 25	A
Attawapiskat River			
Streatfield Iv	105.76	> 25	A
Black Sturgeon River			
at Highway 17	2.89	< 5	
Gardner Rapids	4.78	< 5	P
Current River			
Trowbridge Falls	1.07	< 5	
N. Thunder Bay	1.14	> 25	
Bentley Creek	1.72	> 25	
Dore River			
rapids in first 3.2 km from mouth	2.60	< 5	A
Englehart/Larder (Ottawa River)			
2 stations	7.10	5 - 25	

Site	Potential (MW)	Connection Distance (km)	Cons-traint*
English River			
Mackenzie Lake	9.02	> 25	P
Upper Oak Falls	11.73	> 25	P
Maynard Falls	46.60	> 25	P
Fredrickhouse River			
Neelands Rapids (Twp. Fournier)	2.40	< 5	A
Wanatango Falls (Twp. Mann)	3.04	5 - 25	
Rapids (Twp. S. Clute And Leitch)	9.78	5 - 25	A
French River			
Lower Chaudiere Falls	2.87	> 25	
Dalles	17.24	> 25	P
Five Mile Rapids	20.92	5 - 25	P
Grassy River			
Timmins South	4	< 5	
Groundhog River			
Upper Ivanhoe Lake	2.97	> 25	
near middle of Reeves	3.14	5 - 25	P
Vimy Creek	4.15	5 - 25	P
South Melrose	4.38	> 25	
Whist Falls	12.47	5 - 25	P
16 km Rapids (Twp. Hicks, Stringer & McVicar)	28.41	> 25	P
Gull River			
below Roaring River	2.87	> 25	P
Roaring Rapids	5.80	> 25	P
Kaministiquia River			
Shabaqua Corners	2.88	> 25	A
Hume	4.11	> 25	A
Lot 2 Block 'A' (Twp. Paipoonge)	6.63	> 25	
Mokoman Falls	10.83	< 5	A
Big Beaver Falls	11	5 - 25	
Kopka River			
Mink Bridge Portage	3.91	> 25	

.../cont'd

*A = Agreement, P = Park. Sites having both constraints are listed under Park constraints in the previous summary tables.

Table 3.6.5 - Hydroelectric Potential within Policy Guidelines: New Sites

Site	Potential (MW)	Connection Distance (km)	Cons-traint*
Little Jackfish River			
Mileage 2.5	22	> 25	
Mileage 12.5	62	> 25	
Mileage 7.9	78	> 25	
Little Pic River			
7.2 km from Mouth	1.11	< 5	P
near mouth	2.40	< 5	P
Madawaska River			
Highland Falls	94.10	5 - 25	P
Magnetawan River			
Farm Rapids	3	5 - 25	P
Bying Inlet	4.40	5 - 25	
Mattagami River			
Poplar	6.62	5 - 25	A
Yellow/Island Falls	18	5 - 25	A
Cypress Falls	42.40	5 - 25	A
Grand Rapids	174	5 - 25	A
Missinaibi River			
Black Feather Rapids (Twp. Sanke)	4.84	5 - 25	P
Albany Rapids	6.59	> 25	P
Split Rock Rapids	7.39	> 25	P
Devil Rapids	7.78	> 25	P
Kettle Falls (Twp. Sankey)	9.47	5 - 25	P
Glass Falls	10.37	5 - 25	P, A
Thunder House Falls & Chute	42	> 25	P, A
Long Rapids	126	> 25	P
Patten Post	250	5 - 25	P, A
Moose River			
Renison	135	> 25	A
Grey Goose	140.40	5 - 25	P, A
Mooseland River			
Mooseland Rapids 1	4.30	> 25	P
Mooseland Rapids 2	4.58	> 25	P
Muskoka Musquash			
Gray Rapids	6.73	< 5	A
Muskoka River			
North Bala	4	> 25	

Site	Potential (MW)	Connection Distance (km)	Cons-traint*
Namakan River			
Myrtle Falls	4.80	> 25	
Hay Rapids/High Falls	13.10	> 25	
Nanewaminikan River			
km 8 & km 12.8 (#286 & 288)	8	5 - 25	
Dragonfly Lake	9.80	5 - 25	
Nettogami River			
Nettogami Falls	12.26	> 25	
Newpost Creek			
Mawhinney	6.40	> 25	
Newpost Creek	26.83	5 - 25	P, A
North French River			
Nettogami Island	1.87	5 - 25	
First Rapids	10.26	5 - 25	A
Onaping River			
High Falls	10.38	5 - 25	A
Opasatika River			
Opasatika Rapids I	2.56	> 25	
Breakneck Falls & Rapids	3.77	5 - 25	
Ottawa River			
Chaudiere Falls	7.40	< 5	
Chaudiere Falls#1	7.92	< 5	
Petawawa River			
Crooked Rapids	2.75	< 5	A
Pic River			
Manitou Falls	58	5 - 25	
Rideau River			
Rideau Falls	2	< 5	
Saugeen River			
Port Elgin	7.30	> 25	
Seine River			
Island Falls & rapids above	2	5 - 25	
Steep Rock Mine PGS	500	< 5	

…/cont'd

*A = Agreement, P = Park

Table 3.6.5 - Hydroelectric Potential within Policy Guidelines: New Sites

Site	Potential (MW)	Connection Distance (km)	Cons-traint*
Serpent River			
McCarthy Chute	2.77	5 - 25	P
Severn River			
Port Severn	2.90	< 5	A
19 km below Muskrat Dam Lake	10.14	> 25	A
36.8 km from mouth	10.48	> 25	A
3 km below Muskrat Dam Lake	13.53	> 25	A
8 km from mouth	14.10	> 25	A
12.8 km below Sandy Lake	15.89	> 25	A
9.6 km below Witegoo River	17.05	> 25	A
16 km above Sachigo River	18.83	> 25	A
56 km below North Channel	19.72	> 25	A
5.2 km below Asipoquobah Lake	19.88	> 25	A
2 km above North Channel	30.03	> 25	A
Sachigo	104.44	> 25	A
Blackbear	123.35	> 25	A
Limestone Rapids I	157.55	> 25	A
Limestone Rapids II	170.73	> 25	P
Steel River			
Santoy Lake	6	5 - 25	
Sturgeon River			
Island Lake	2.50	> 25	
Ragged Chute	3.60	> 25	
Trent River/Canal			
Fenelon Falls	2.60	< 5	
Trent University	4.10	< 5	
Glen Miller	8	< 5	
University River			
Denison Falls	35.50	5 - 25	P, A
Vermilion River			
at Soo Crossing	1.49	< 5	A
Cascade Falls	1.54	< 5	

Site	Potential (MW)	Connection Distance (km)	Cons-traint*
Wabigoon River			
Wabigoon Falls	2.70	> 25	
Wanapitei River			
km 4.8 - McVittie S	1.60	5 - 25	
Welland River/Canal			
Gibson	5	< 5	
White River			
3.2 km below White Lake	8.50	5 - 25	P
1.6 km below Chicagonce Falls	11.50	5 - 25	P
Umbata Falls	23	5 - 25	P
Whitefish River			
below Cross Lake	2.20	< 5	
Lang Lake (La Cloche Mts.)	2.30	> 25	
Winisk River			
Wunnummin Lake 2	14.12	> 25	A
Gneiss Rapids	32.88	> 25	P, A
Seashell Rapids	37.05	> 25	P, A
142.2 km from mouth (Atik Island)	64.34	> 25	P, A
12.8 km from mouth (Winisk P.O.)	94.74	> 25	P, A
33.6 km from mouth (Shamattawa River)	111.57	> 25	P, A
59.2 km from mouth (Maminiska River)	130.15	> 25	A
Fractional MW Sites	30		

Source: OPA, MNR

*A = Agreement, P = Park

The following table lists the portion of the 1,447 MW of potential that would involve the upgrading or extension of existing sites.

Table 3.6.6 - Hydroelectric Potential within Policy Guidelines: Upgrades and Extensions

Site	Potential (MW)
Nipigon River	
Runner Upgrade - Alexander	0.6
Runner Upgrade - Cameron	4
Madawaska Rriver	
Runner Upgrade - Mountain Chute	4
English River	
Runner Upgrade - Caribou Falls	4.9
Mattagami River	
Runner Upgrade - Little Long	10
Runner Upgrade - Harmon	12
Runner Upgrade - Kipling	12
Abitibi River	
Abitibi Canyon	30
Niagara River	
Beck Tunnels	50
Mattagami River	
Extension - Little Long	61
Extension - Harmon	68
Extension - Kipling	68
Total (MW)	**324.5**

Source: OPA, OPG

3.6.7 Appendix 2: References and Credits

The following sources of information were used in the compilation of the hydroelectric input to the Generation Mix Report:

References:

- Hydropower Engineering, C.C. Warnick © 1984 Prentice Hall
- Ontario Hydro's History and Description of Hydroelectric Generating Stations, © 1991 Ontario Hydro
- Hydroelectric Resources, A Quick Reference Guide, © 2001 Ontario Power Generation
- Hydroelectric Power Resources of the Province of Ontario, Report no. 87360 C.K. Jonys, P. N. Chang, © 1987, Ontario Hydro, Geotechnical and Hydraulic Engineering Dept.
- NRCAN database, Natural Resources Canada, 2005 - to be found at www.small-hydro.com
- MNR database, Ontario Ministry of Natural Resources, 2004, Renewable Energy Section, Lands and Waters Branch, Peterborough, Ontario.
- A report on Hydroelectric Potential in Ontario, © 2005 Hatch-ACRES Commissioned by the Ontario Waterpower Association, Peterborough, Ontario.
- Transmission Solutions: "A 10-year transmission plan for the Province of Ontario", © 2005 Hydro One Inc.
- A 10-year Outlook : "An assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario", © 2005 IESO – Report IESO_REP_0245 Ver 1.0

Credits:

- The Renewable Energy Section, Lands and Water Branch, Ministry of Natural Resources, Peterborough, Ontario.
- Ontario Waterpower Association 380 Armour Road, Peterborough, Ont. Paul Norris, President
- Hydro One Networks, Inc. Transmission Regulation Division, David Curtis, Director.
- Hatch-ACRES International, Small Hydro Division, Niagara Falls, Ont., Murray McFarlane, Director.

3.7 Provision for Managing Decommissioned Nuclear Generation and Spent Nuclear Fuel

The purpose of this paper is to introduce the background for the current status of managing decommissioned nuclear generation and spent nuclear fuel. In doing so, it summarizes the legal environment, financial provisions required of nuclear operators, related activities in other countries and the role of the Nuclear Waste Management Organization (NWMO) and its recent recommendations. These considerations will have implications for the supply mix advice as it relates to Ontario's existing nuclear and any new nuclear facilities.

3.7.1 Key Findings

- *Federal Nuclear Fuel Waste Act, 2002*, (NWFA) established Nuclear Waste Management Organization (NMWO) to propose approaches for the management of nuclear fuel waste and implementing the approach that is selected and approved; commercial nuclear reactor owners support NWMO through regulated contributions other support
- NWMO issued a report in November 2005 on the alternative methods of long-term management in "Choosing a Way Forward – The Future Management of Canada's Used Nuclear Fuel"
- NWMO has assessed three technical options specified by the Nuclear Waste Management Organization (NFWA) – Deep Geological Disposal; Storage at Nuclear Reactor Sites and Centralized Storage – and added Adaptive Phased Management
- NMWO did not review appropriate role for nuclear power as part of this process
- Adaptive Phased Management was the recommended alternative – incorporation of social concerns was a strong driver in reaching this conclusion
- Canadian Nuclear Safety Commission (CNSC) was established in 2000 under the *Nuclear Safety and Control Act* to regulate operation, use and management of nuclear materials
- In 2005, CNSC issued a draft regulatory guide specifying that all nuclear facilities must have in place a decommissioning plan that conforms with detailed specifications
- Financial provisions respecting Ontario nuclear liability are contained in a consolidated guarantee to CNSC in the areas of decommissioning of Ontario nuclear facilities, nuclear waste management and a provincial guarantee for remaining costs. The total value of the guarantee to CNSC is $4.5 billion
- *Nuclear Liability Act* sets out required insurance, provision for risks covered by the operators, their insurance companies and the federal government
- Other countries are following somewhat similar paths in their methods of dealing with wastes, although the specifics of each country vary somewhat

- In November 2005, the NWMO recommended to the federal government, addition of the Adaptive Phased Management approach, which provides for deep, underground containment with the opportunity for retrievability at a future time

3.7.2 Introduction

This section of the report summarizes the following:

- Legal environment behind the safety of the Canadian nuclear industry, and more particularly, the Ontario nuclear industry, including the issues surrounding decommissioning and waste fuel management for nuclear generating facilities
- Financial provisions required of owners of nuclear power stations, and the current state of these provisions
- Status of similar activities in other countries and
- Activities of the NMWO, its mandate, and the results of its work to the fall of 2005

3.7.3 Financial and Economic Issues

3.7.3.1 Laws and Financial/Economic Factors

Historical Background

In 1978 the governments of Canada and Ontario directed Atomic Energy of Canada Limited (AECL) to develop the concept of deep geological disposal of nuclear fuel wastes. A subsequent joint statement in 1981 established that the selection of such a site would not begin until after full federal public hearings and approval of the concept by both governments. In 1998, an Environmental Assessment Panel was established to review the concept and a broad range of nuclear fuel waste management issues in a public process.

The panel estimated the facility cost for deep disposal to be $8.7 billion to $13.3 billion in 1991 dollars. After public consultations and much other study, the panel issued its report in February, 1998. The panel concluded that:

- Broad pubic support is necessary in Canada to ensure acceptability of a concept for managing nuclear fuel wastes.
- Safety is a key part, but only one part, of acceptability. Safety must be viewed from two complementary perspectives: technical and social.

The panel continued on to define safety and acceptability criteria, including requiring the support of Aboriginal people and comparison with other alternatives. After applying the criteria to the deep disposal concept, the panel arrived at two key conclusions:

- "From a technical perspective, safety of the AECL concept has been on balance adequately demonstrated for a conceptual stage of development, but from a social perspective, it has not.
- As it stands, the AECL concept for deep geological disposal has not been demonstrated to have broad public support. The concept in its current form does not have the required level of acceptability to be adopted as Canada's approach for managing nuclear fuel wastes."

The panel went on to make a number of key recommendations, including: creating a nuclear fuel waste management agency at arms length from the utilities and AECL, with arrangements for its funding by the producers and owners of nuclear fuel waste; developing a comprehensive public participation plan; developing an ethical and social assessment framework; and, developing and comparing options for managing nuclear fuel wastes. Other recommendations added support and specifics to these recommendations.

The Nuclear Fuel Waste Act

Subsequently, the Canadian parliament approved the NFWA in June 2002, and it came into force November 15, 2002.

This act establishes the organization as the NMWO. It also outlines NWMO's objectives, funding, accountability and oversight and reporting requirements. The NWMO is established as a non-profit organization with the purpose of:

- Proposing to the government of Canada approaches for the management of nuclear fuel waste; and
- Implementing the selected and approved approach.

The Act also defines the involved "nuclear energy corporations" to be Ontario Power Generation (OPG), Hydro-Quebec (HQ), New Brunswick Power Corporation, and any other body that owns nuclear fuel waste resulting from the production of electricity by means of a commercial nuclear reactor. This includes successors or assignees of these corporations. It also includes any assignee of AECL.

The purpose of the act is to permit the government to make a decision on the management of nuclear fuel waste. Nuclear fuel waste is defined as irradiated fuel bundles removed from a commercial or research nuclear fission reactor.

Each of the named corporations is required to become and remain a member or shareholder of NWMO. NWMO is required to offer, at a cost reasonable in terms of its costs, management of nuclear fuel wastes to its members and to all owners of nuclear fuel waste produced in Canada that are neither members nor shareholders of NWMO.

NMWO is required to create an Advisory Council to examine the study as it proceeds and report to the federal Minister of Natural Resources on a triennial basis. The members of the Advisory Council are expected collectively to have the following attributes: a broad range of scientific and technical disciplines related to the management of nuclear fuel waste; experience in nuclear energy matters, in public affairs, and as needed in other social sciences; expertise in traditional aboriginal knowledge; and inclusiveness of representatives nominated by affected local and regional governments and aboriginal organizations.

NMWO is financed through a strictly regulated financing structure which requires each of the nuclear energy corporations and AECL to maintain a trust fund in Canada. In the case of the nuclear energy corporations, the funds are to be held by a financial institution. All records relating to the trust funds must be maintained in Canada.

The initial funding of the trust fund was as follows:

- Ontario Power Generation Inc. - $100,000,000
- Hydro-Quebec - $4,000,000
- New Brunswick Power Corporation - $4,000,000
- AECL - $2,000,000

These contributions were established to be paid annually, subject to annual revision when the Minister subsequently approved the amount of deposit at a different level. There are severe penalties in the event that the corporations fail to contribute to the funds as required and the detailed status of the funds is subject to auditing by independent auditors. Only the NWMO may withdraw monies from the fund and then only on a restricted basis.

Within three years of the Act, (coming into force in Nov. 2002), the NWMO was required to submit a report to the Minister setting out:

- Proposed approaches for the management of nuclear fuel waste, together with the comments of the Advisory Council.
- A recommendation as to which approaches should be adopted.

The Act requires that each of the following methods must be the basis of at least one approach:

- Deep geological disposal in the Canadian Shield, per the previous study.
- Storage at nuclear reactor sites; and
- Centralized storage, either above or below ground.

The study must include detailed technical descriptions, specified economic regions for implementation, comparisons of costs, risks and benefits, as well as ethical, social and economic considerations for each approach. It must also include a description of the nuclear fuel waste management services to be offered by the NWMO. Descriptions of activities, timetables for execution, proposed methods for minimizing or avoiding socio-economic effects, and a program for public consultation are required. The NWMO may nevertheless propose new methods if it has been subjected to expert scientific and technical review by international governmental organizations that deal with nuclear matters.

The study is also required to establish a formula to calculate the annual amount required to finance the management of nuclear fuel waste, together with the estimated amounts to be received from owners of nuclear fuel waste other than nuclear energy corporations and AECL.

The study report is to be made a public document. Indeed, the report was issued publicly in November 2005, as required. The NWMO has recommended Adaptive Phased Management, a fourth approach developed by the organization that builds on the strengths of the three methods specified by the NFWA. Following review by the Minister of Natural Resources, one of the approaches will be chosen.

There is more detail on the specific activities that have been undertaken by the NWMO further in this report. Funding matters for Ontario are dealt with under Provincial Activities below.

Federal Activities

Canadian Nuclear Safety Commission

The *Nuclear Safety and Control Act* (NSCA) came into force on May 1, 2000 and provides the regulatory authority for the CNSC, the agency which sets and enforces rules for the safe operation, use and management of facilities and materials related to the nuclear and radioactive materials area, including nuclear power.

The Act specifically charges CNSC with:

- Regulation of the development, production and use of nuclear energy and the production, possession and use of nuclear substances, prescribed equipment and prescribed information in order to:
  - prevent unreasonable risk to the environment and to the health and safety of persons associated with it
  - prevent unreasonable risk to national security associated with it, and

  - achieve conformity with measures of control and international obligations to which Canada has agreed.

- Dissemination of objective scientific, technical and regulatory information to the public concerning the activities of the Commission and the effects on the environment and on the health and safety of persons, of the development, production, possession and use of nuclear substances, prescribed equipment and prescribed information.

CNSC is active in monitoring the day-to-day activities in nuclear power facilities across Canada, reviews applications from nuclear power plant owners for significant changes in the physical facilities, their operation, funding, maintenance, security, staffing, etc., as well as continuously monitoring and revising regulatory requirements in order that nuclear facilities meet stringent targets for protecting the public, the staff, and the environment.

CNSC issued a Draft Regulatory Guide in April 2005, entitled "Assessing the Long Term Safety of Radioactive Waste Management." It provides extensive and detailed requirements for assessments required to be submitted on the subject matter. The document, notably, does not deal with the social aspects of the subject. However, it does deal with radiological and environmental issues. Specifically, it mentions that regulations under the NSCA identify five facility licences required:

- Site preparation license
- Construction license
- Operating license
- Decommissioning licence
- Licence to abandon

The Guide also notes that "All facilities must have a decommissioning plan in place, identifying the end-state of the facility and site, the activities to achieve that end-state, and including an assessment of the potential environmental effects of the proposed decommissioning program."

This decommissioning plan forms the basis for the financial guarantee. This is required to ensure that there will be funds available to implement the decommissioning plan and to prevent any financial burden on future generations.

The requirements outlined in the draft guide are extensive and include methods and requirements for dealing with ultra-long term and extraordinary effects, such as those that might occur in the event of an earthquake or similar major disaster. There is an emphasis in the document on defence in depth.

The subjects covered in detail extend from initial planning, through operation, to decommissioning and waste fuel management. Based on experience to date, the reasonable conclusion that can be made is that the CNSC and its predecessor, the Atomic Energy Control

Board (AECB), are effective regulators operating in a manner that provides protection to plant personnel, the public and the environment.

The Nuclear Liability Act

This act deals with civil liability for nuclear damage. It spells out the legal liability of the plant operator(s), exceptions to the liability, the amount of insurance that an operator is required to carry with insurance agencies, the residual risks carried by the government and the payment by the operator to the government to contribute to managing that risk.

The Act does not include a specific purpose other than civil liability for nuclear damage. However, it serves the purpose of attempting to put some bounds on potentially very large liabilities. It also does so in the manner in which those liabilities are dealt with in the legal system, making the use of nuclear generation practical in a financial risk sense.

Provincial Activities

Activities within provincial agencies in Ontario, other than those normal activities required by nuclear operators to comply with the safety requirements of the CNSC, are primarily financial in nature. They are divided into three main areas:

- The Ontario Nuclear Funds Agreement (ONFA) – 1999
- The Provincial Guarantee Agreement
- The activities of Ontario Power Generation (OPG)

Bruce Generating Station, operated by Bruce Power, is included with OPG's responsibilities because the station is only leased from OPG. OPG retains decommissioning and waste fuel management responsibilities.

Funding requirements for decommissioning and waste are dependent on planning assumptions regarding plant life, disposal methods and processes for waste fuel, and the disposal methods and processes for management of the decommissioned generating stations and/or their radioactive components. Current (2003) assumptions are:

- Central storage of Operational Waste at reactor sites.
- Storage capacity for 40-year life and beyond.
- Dismantle reactors 30 years after end of life.

Underground disposal of used fuel and waste is assumed for financial planning (used fuel) starting in 2035, low and intermediate level (L&ILW) waste start in 2015.

In a hearing before the Canadian Nuclear Safety Commission for the amendment of licences for the OPG-owned nuclear generation, OPG had its assumptions, plans, and funding guarantee processes all reviewed. While this occurred in a critical environment, OPG received approval from CNSC, subject to ongoing monitoring by the CNSC to deal with possible changes to various parameters of the agreement. The total cost for facility decommissioning was estimated at that time to be $7.474 billion (2003 dollars). The total present value of these costs was determined to be $6.263 billion.

OPG described the proposed structure of a consolidated guarantee to address the above liabilities. It is divided into three parts:

- The Ontario Nuclear Funds Agreement (ONFA)
- The Nuclear Fuel Waste Act Trust (NFWA trust); and
- A provincial Guarantee Agreement (PGA)

The Ontario Nuclear Funds Agreement (ONFA) was established in 1999 and consists of a segregated fund that is being built up over time for the express purpose of financing the future decommissioning of OPG's nuclear facilities. OPG reported at the 2003 hearing that ONFA contained approximately $4.9 billion and was expected, by 2007, to contain most of the present amount value noted above.

The NFWA trust is a fund required to be maintained under the *Nuclear Fuel Waste Act*. OPG had contributed approximately $500 million to the NFWA trust at the time of the hearing and would continue to contribute. It is required to make annual deposits until a fuel waste disposal option is chosen by the Federal Government.

Through the Provincial Guarantee Agreement (PGA) with CNSC, the Province of Ontario also agreed to provide a guarantee to cover the balance of the total cost estimate. It was proposed that the PGA expire in 2007 when the ONFA funds would be sufficient to cover the total cost estimate. In summary, OPG reported the following, effective January 1, 2003.

Table 3.7.1 – Nuclear Funding Agreements (2003)

Ontario Nuclear Funds Agreement	$4,050 million
Nuclear Fuel Waste Act trust	$503 million
Provincial Guarantee Agreement	$1,710 million
Total	$6,263 million

Source: OPG

CNSC accepted this information and amended nuclear licences accordingly. Among the conditions included were a requirement for periodic reporting and review, with possible adjustments if required to maintain adequate funding.

In July 2003, OPG and the Province of Ontario completed arrangements, pursuant to the ONFA, which required the establishment of segregated custodial funds to hold the nuclear fixed asset removal and nuclear waste management funds. OPG then transferred the assets in its then-existing nuclear fuel asset removal and nuclear waste management funds to a Decommissioning Fund and a Used Fuel Fund, held in segregated custodial accounts. In addition, a receivable due from the Ontario Electricity Financial Corporation of $3.1 billion was transferred into the funds in the form of a $1.2 billion cash payment and a $1.9 billion interest-bearing note receivable.

The Decommissioning Fund will be used to fund the costs of nuclear fixed asset removal and long-term low and intermediate waste management, and a portion of used fuel storage costs after station life. The Used Fuel Fund will be used to fund future costs of long-term nuclear waste management, subject to graduated liability thresholds specified in the ONFA, which limit OPG's total financial exposure to approximately $6.0 billion (PV at April 1, 1999). Required funding in 2004 under ONFA was $454 million, including $100 million to the Ontario NFWA trust.

The NFWA trust is the value of the combined PGA and ONFA funding. The value of the guarantee to CNSC is $4,500 million.

3.7.3.2 Experience in Other Countries

Experience in other countries around the world has been evolving rapidly, given the evolution of improved nuclear technology, the cost and impending security implications of dependence on oil and gas, and the broadly held determination to decrease greenhouse gas emissions. The current status of the nuclear industry in some of the countries is outlined briefly below:

The United Kingdom

There are 23 reactors generating about 20% of the electricity required in the U.K. The U.K. has full fuel cycle facilities, including major reprocessing plants. The U.K. has ambitious greenhouse gas reduction targets, but the government commitment to the future of nuclear energy seems somewhat uncertain. Reprocessing spent fuel is done by British Nuclear Group. Recycling plutonium is not regarded as economic, so separated plutonium is stored indefinitely.

Solid low-level wastes are disposed of at a repository near Sellafield. Intermediate level wastes are stored at Sellafield and other sites, pending disposal. High-level wastes are stored at Sellafield, some vitrified and stored in stainless steel canisters in silos. All high-level waste is to be stored for 50 years before disposal to allow cooling.

The U.K. government is advised by the Radioactive Waste Management Advisory Committee which is again charged with reviewing the options for long-term storage/disposal.

France

France has 59 reactors operated by Electricite de France (EdF), totaling more than 63,000 MW, and supplying about 78% of the total energy demand.

After the first oil shock in 1974, the French government decided to rapidly increase the country's nuclear power capability. Consequently, France now claims a substantial level of energy independence and one of the lowest electricity costs in Europe. A new Energy Act is anticipated in 2005 based on three elements: demand management, development of renewables and nuclear power.

France uses some 12,400 tonnes of uranium oxide concentrate per year for its electricity generation, of which much comes from Canada and Niger. It is self-sufficient in conversion, enrichment, fuel fabrication, reprocessing and MOX (mixed oxide) fuel fabrication plants. It also has a waste management program.

Spent fuel from reactors is sent for reprocessing, extracting the plutonium and uranium, leaving high-level wastes. These are vitrified and stored at the La Hague plant in Normandy for later disposal.

The national policy is to reprocess spent fuel to recover useful fuel components and reduce the volume of high-level wastes. Waste management research is done at an underground rock laboratory in eastern France, situated in clays. Another laboratory is researching granites. ANDRA, the waste management agency, expects to report to government so that parliament can decide in 2006 on a precise course of action.

EdF sets aside EUR 0.15 cents/kWh of nuclear electricity for all back-end costs, but there is some dispute over whether this is adequate.

Eleven experimental and power reactors are being decommissioned in France. There are well-developed plans for dismantling these reactors, but progress awaits the availability of sites for disposing of the intermediate-level wastes and the alpha-contaminated graphite from the early reactors.

Sweden

Sweden remains on course to begin operating the world's first deep geological repository for spent nuclear fuel. The repository construction application is likely to be ready for submission in 2008 and the repository operational by 2017. Site selection and canister testing are underway and drilling, in preparation for safety assessments, has reached the halfway point. The results look promising. The candidate sites are close to two of the country's four nuclear plants.

Finland

Finland has four nuclear reactors providing 27% of its electricity. In May 2002, parliament voted to support the building of a fifth reactor on economic, energy security and environmental grounds. This reactor is now under construction for a 2009 startup.

TVO, the Finish utility, has bought uranium from Canada, Australia and Africa and had it converted to UF6 in Canada and France and enriched in Russia. Fuel fabrication has been in Germany, Sweden and Spain.

Finland's nuclear waste management program was initiated in 1993. The law requires that the wastes should be handled wholly in the country. Responsibility for nuclear wastes remains with the power companies until its final disposal. Reactor decommissioning is the responsibility of the two power companies separately, and plans are updated every 5 years.

At Olkiluoto, a surface pool storage for spent fuel has been in operation since 1987. It has a 1,270 tonne capacity and is designed to hold spent fuel for about 50 years, pending deep geological disposal. An additional pool exists at Loviisa.

Posiva Oy was established in 1995 as Finland's joint-venture company for final disposal of spent nuclear fuel. It has well advanced plans for a deep geological repository for encapsulated spent fuel, some 500 metres down in 2-billion year-old igneous rock.

Encapsulation of waste fuel will involve putting twelve spent fuel assemblies into a boron steel canister and enclosing this in a copper capsule. Each capsule will be placed in its own hole in the repository and backfilled with bentonite clay. Access will be maintained and the spent fuel will be recoverable.

Overall costs of radioactive waste management in Finland, including decommissioning, are estimated at EUR 0.23 cents/kWh undiscounted – about 10% of total power production cost.

3.7.4 Technical Options

The NWMO was mandated to assess three technical options specified by the NFWA, and developed a fourth option, Adaptive Phased Management, on the basis of public input. This section discusses the options in terms of their benefits, risks, costs, and timelines, as well as the studies that have been carried out regarding these options over the past several decades.

3.7.4.1 Discussion of Studies

The three methods specified by the NFWA are well understood and considered to be technically credible and viable. Storage technologies have been demonstrated for many years, and deep geological disposal has been studied for decades leading to advanced scientific and technical understanding internationally.

The study and advancement of technology for the transport, storage and permanent disposal of Canada's nuclear fuel waste has been underway for the past several decades. In 1978, the governments of Canada and Ontario established the Canadian Nuclear Fuel Waste Management Program, which had continued to research, develop and demonstrate interim and long term disposal options.

Additionally, licensed interim storage methods have been designed and implemented by all of Canada's nuclear waste owners, who have also submitted conceptual long-term storage designs to the NWMO. Since 1978, Canada has spent over $800 million dollars on used fuel development. In recent years, OPG has managed the technology development program on behalf of the waste owners, ensuring that deep geological storage can be implemented should the government decide to do so.

In 1994, AECL submitted a proposal on its concept for a deep geological repository. In 1998, the Seaborn Panel reported on the AECL proposal, identifying technical issues derived from the findings of the Panel's Scientific Review Group. OPG has been addressing these technical issues since 1996, documenting progress in a series of annual reports.

Research and development at OPG is complemented by ongoing research and development by technical experts at AECL, Canadian universities, and Canadian and international consultants. OPG also has co-operation and information sharing agreements in place with radioactive waste management organizations in Sweden, Finland and Switzerland. Additionally, Canada participates in international waste management activities through the OECD Nuclear Energy Agency, improving the understanding and enhancing the technology base related to deep geological storage.

For the NWMO study, independent engineering consulting firms were retained by the Joint Waste Owners to produce conceptual engineering designs for the three options identified in the NFWA. A third-party review was commissioned by the NWMO to review the appropriateness of the key engineering design assumptions adopted in these conceptual designs. Engineering consulting firms also reviewed the technical feasibility of the Adaptive Phased Management approach, which itself was based on the conceptual designs for each of the three NFWA options.

3.7.4.2 Discussion of Options That Were Ruled Out

The NWMO examined three used fuel management methods that are currently receiving international attention, but screened these out of the comparative analysis: reprocessing, partitioning and transmutation; placement in deep boreholes; and, the international used nuclear fuel repository concept. Although screened out, Canada may wish to monitor and research international developments regarding these options.

Reprocessing was screened out for a number of reasons. These include high cost, the fact that residual radioactive wastes are more difficult to manage than those from unprocessed wastes, and the fact that weapons-grade material can be separated out during processing. Partitioning and transmutation were ruled out because the technology and process are still developmental, and long-term management of residual materials would still be required. Placement in deep boreholes was ruled out as significant technical questions remain as to the mechanical integrity of this approach, necessitating further research and development.

The international repository concept (with Canada as host or another country as host) was screened out. The reason was that the facility would require the same assessment as a domestic option in terms of costs, risks and benefits, as well as implicating all the societies and cultures that would be involved. Additionally, transportation of fuel could contradict existing guiding principles that place full responsibility for the long-term management of used fuel on those who produce it.

Eight additional methods were screened out because they either contravened international treaties or were characterized by insufficient proof-of-concept. Examples of these methods include disposal at sea, in space or in ice sheets.

3.7.4.3 Discussion of Options that Were Considered

Option 1: Deep Geological Disposal

Description: Under this approach, used fuel would be placed in a central location deep within the Canadian Shield (500-1,000 metres below surface), in durable corrosion-resistant containers that can be designed to last a minimum of 100,000 years and withstand the effects of glaciation. Used fuel would be transported from existing interim storage facilities at nuclear reactor sites. After placement of the waste underground, the waste would be monitored for a period of time prior to backfilling the repository with high performance concrete and/or swelling bentonite clay.

Once backfilling was completed, the surface facility would be decontaminated and dismantled, returning the site to greenfield conditions. Backfilling would limit the movement of groundwater and dissolved material, while the crystalline rock of the Canadian shield isolates

the waste from the surface environment. This geological formation is stable in the long term, has good rock strength, low groundwater flow, is low in minerals, and is at a sufficient depth that it is unlikely to be disturbed in the future.

Costs and Timeline: The earliest that the facility could be ready would be 2035, if a decision was made by government in 2006 to proceed with this option. Siting would take approximately 15 years, as would design and construction. It would take about 30 years to place the fuel, which would be monitored for an additional 70 years. Decommissioning and closure would take approximately 12 and 13 years, respectively.

This option is estimated to cost $16.2 billion (2002 dollars) which, based on long-term economic factors, corresponds to a present value cost of $6.2 billion (2004 dollars).

Benefits: With deep geological disposal, used fuel is permanently placed underground and sealed. As a result, the need for on-going institutional management and financing is reduced, if not eliminated. This becomes important in the event of social destabilization or institutional change. In the longer term, exposure to hazards is limited as the facility is centralized and designed to be passively safe.

The geological barriers of the site combined with the long-lived engineered barriers are designed to isolate the used fuel for the period over which it remains hazardous. Though the risk of movement of radioactivity into groundwater exists for hundreds of thousands of years, the predicted impact is below applicable standards because of the isolation provided by the geological barrier.

The facility could be sited away from population centres to minimize risk. The probability of intrusion and other security threats are very low in the long term. Ongoing repackaging, handling and transportation of used fuel are eliminated as the material is placed in the deep repository. The used fuel will, however, need to be repackaged once for transportation, and possibly again prior to placement in the deep repository.

Compared to other options, deep geological storage provides significant advantages with respect to withstanding long-term environmental change, such as climatic change, extreme weather, changing water levels, glaciation and seismic activity.

Risks and Uncertainty: Future generations are provided with little flexibility as to how waste is managed, because decisions cannot be reversed without significant costs and increased risks. Waste has to be transported to the central facility, creating attendant risks (though these are deemed to be very small, due to robust containers that are designed to withstand both normal and extreme events). Risks associated with transportation will tend to increase with distance transported and number of trips.

Siting may be difficult, as communities may be unwilling to host such a facility. There may be adverse environmental effects associated with the construction of the site in the short term. There is some uncertainty associated with long-term performance of the option, as it is not possible to provide advance "proof of concept" given the very long timeframe. Assurances of performance are based on scientific studies, models, codes and natural analogues. Monitoring of the waste and undertaking corrective actions are more difficult as compared to other options, as is retrieval of the waste should a future use be found for it.

The NWMO report suggests that there is a lack of confidence among Canadians that the waste can be transported safely and that existing knowledge is sufficient to proceed with this option at the current time.

Option 2: Storage at Nuclear Reactor Sites

Description: This option involves continuing to manage waste at the seven existing nuclear reactor sites into perpetuity, at or below surface. Existing dry storage facilities would be expanded, or new facilities built at each of the reactor sites. If new facilities were built, the existing waste would have to be transferred to the new facilities. Processing and storage buildings and facilities would require ongoing maintenance, inspection and security, and would eventually have to be replaced. Fuel would have to be repackaged in new containers and moved to new buildings, with the old containers and facilities either refurbished or demolished.

Based on current assumptions, the fuel would require repackaging every 100 years and facilities would have to be completely refurbished once every 300 years. The tasks associated with a complete replacement and refurbishment cycle is expected to take 30 years to complete.

Costs and Timeline: If a government decision was made in 2006 to proceed with this option, and implementation began immediately, the sites would be ready between 2016 and 2020. Though there may be variation across reactor sites, typically siting and approvals and design and construction would each take five years. Initial transfer of fuel from interim to long-term storage would take 35 to 40 years. Monitoring, building refurbishment and fuel repackaging would extend beyond 50 years.

Costs for this option are estimated to be between $17.6 billion and $25.7 billion (2002 dollars) for one 300 year cycle, and these costs would continue indefinitely. The present value cost of one cycle is approximately $2.3 billion to $4.4 billion (2004 dollars).

Benefits: Future generations have flexibility in influencing the evolving management of nuclear waste, and to take advantage of new learning and information. Monitoring human health and environmental effects is easier than deep geological storage, as is taking any required corrective action. Existing knowledge, technology, skills and processes are well-developed and in place to support existing nuclear facilities. The ability to monitor and demonstrate the technical

performance of this option is also high. It is expected that this capacity would persist in the near term.

No transportation of the nuclear fuel would be required, eliminating any off-site transportation related risks. Should new uses be found for the waste in future, this option would provide for long-term access and retrieval. Construction of a deep repository, associated short-term environmental effects and the need to develop a greenfield site are avoided.

Risks and Uncertainty: With the lack of natural barriers, this approach requires on-going institutional management and financing, creating risks in the event of institutional change or social destabilization. There is a high degree of uncertainty as to the continuity of human institutions given the very long timeframe under consideration. Similarly, this approach is vulnerable to risks arising from environmental change, which are deemed to increase in the long term. This is particularly salient given the proximity of existing reactor sites to large bodies of water and location in higher seismic zones, as extreme events could result in international consequences.

Existing reactor site communities would be obligated to long-term management of used fuel, which was not envisioned when the nuclear plants were initially sited. This option poses greater risk to the public given the fact that several existing reactor sites are located near relatively large population centres. In addition, management of the waste will be required well after the reactors have been decommissioned.

The existence of multiple sites compounds the potential costs and risks associated with this option vis-à-vis a centralized facility. There are few, if any, contingency plans should the sites become compromised. As many as 100 repackaging cycles may be required over a 10,000 year period. Human intrusion into the facility is likely if institutional control is not maintained, raising attendant security risks.

Option 3: Centralized Storage

Description: This option involves above or below ground storage at a new centralized facility. The facilities could be just under the surface and mounded over, or 50 metres below ground in bedrock. Used fuel would be transported from existing interim storage facilities to the new site, which would take approximately 30 years and would require an emergency response plan.

Facilities required would include those for producing transportation containers, for loading fuel into the containers, for producing storage containers, and for moving fuel from the transport to long term storage containers. The mode of transportation would depend on the location of the site. Similar to Option 2, repackaging of the used fuel would be required every 100 years, and complete refurbishment and replacement of the facility once every 300 years.

Costs and Timeline: The earliest the storage facility could be ready would be 2023, if a government decision to proceed with this option was made in 2006. Siting and design and construction would each take approximately 20 years, initial fuel receipt 40 years, and extending monitoring and building refurbishment and fuel repackaging beyond 50 years.

The cost of this option is between $15.7 billion and $20 billion (2002 dollars) for one 300-year cycle, with a present value cost of approximately $3.1 billion to $3.8 billion (2004 dollars).

Benefits: Future generations have the flexibility to influence future waste management approaches, and this option enables monitoring and the ability to take corrective action if necessary. Long-term access to the used fuel is possible, should improved management techniques or new uses be found for it in the future. Since the site geology is not a critical factor for this approach, more siting options are available. The centralized site limits exposure of populations to hazards, and the site can be chosen and designed to protect health and safety and to limit transportation distances.

The performance of the option is well understood with existing science and technology, and the potential to monitor ongoing performance is also high given that storage is close to the surface. To date, existing skills and processes have protected health and safety, and this capacity is expected to continue in the near term. Like Option 2, Option 3 avoids construction of the deep geological repository with associated short-term environmental impacts.

Risks and Uncertainty: Similar to Option 2, Option 3 requires on-going institutional management and financing into perpetuity, creating risks associated with institutional change and social destabilization, particularly given high uncertainty around the continuity of human institutions. As with Options 1 and 4, there may be community resistance when siting this facility. Although the risk is deemed to be small, this option would require transportation of the used fuel to the centralized facility.

Exposure to risk arising from environmental change increases in the long-term, although it can be partly mitigated through careful selection of the centralized site, and because there is only one facility. Like Option 2, Option 3 also requires ongoing repackaging cycles, stretching over 10,000 years and involving as many as 100 cycles.

More ongoing security measures are required as compared to Options 1 and 4, although the centralized facility makes security management easier than in the case of Option 2. Human intrusion into the facility is likely in the event of institutional failure. While likely less than the deep geological repository, construction of the facility could result in adverse short-term environmental impacts. Should the waste need to be removed from the site, a contingency plan is lacking.

Option 4: Adaptive Phased Management

Description: This option consists of staged management approach that is implemented in three stages: preparing for central used fuel management; central storage and technology demonstration; and long-term containment, isolation and monitoring. It combines features from each of Options 1, 2 and 3 and allows for future decisions to be made concerning whether centralized storage should be built prior to permanent storage in the deep repository, when to move fuel from existing sites to the central facility, the duration of research at the selected site, and the timing of construction and closure of the deep repository. In addition to the rock of the Canadian Shield, Ordovician sedimentary rock could also house the deep geological repository, creating more siting options.

During the first stage, further citizen engagement would occur, technology and processes would be further developed and certified, and necessary assessments, approvals and licenses would be obtained. During the second stage, used fuel would be transported to the central site, if the decision was made to construct interim shallow underground storage.

If the decision were made to omit shallow underground storage, existing fuel would remain at the reactor sites. Testing would continue at an underground research laboratory on the site, as would assessment and design. A decision on when to construct the deep repository would be made during this phase.

If interim shallow underground storage was opted for, this waste would be retrieved and repackaged during Phase 3. Otherwise, the used fuel would be transported to the central facility at this time. Waste would be placed in the deep repository at this time, with ongoing monitoring and maintained access to the facility. A future generation would decide when to permanently close the facility.

Costs and Timeline: If the government decided to implement this option in 2006, construction of the shallow storage facility and underground research lab could be completed by 2035, and the deep geologic repository ready by 2065. Siting would take approximately 20 years, design and construction of shallow storage 10 years, and greater than 30 years for each of transportation to the central facility and placement in the deep repository. Extended monitoring would continue to 300 years, with decommissioning and closure taking 25 years and post-closure monitoring continuing indefinitely.

This option is estimated to cost $24 billion (2002 dollars), which is approximately equal to present value costs of $6.1 billion (2004 dollars). If shallow underground storage is omitted, this option is estimated to cost $22 billion (2002 dollars) with a present value of approximately $5.1 billion (2004 dollars).

Benefits: This option attempts to maximize flexibility in the near term while ensuring that an option is available in the long term to contain that isolates the used fuel without requiring

ongoing human intervention. Future generations will be able to influence decisions on waste management in the final stages, during the timeframe in which societal institutions are expected to remain strong. A period is provided over which the performance of the facility can be tested, validated and improved, and contingency plans can be developed for each stage.

Confidence in the geological repository concept and in the safety of transportation can be built over this time, and additional measures can be taken if deemed necessary. New learning, science and technology can be incorporated and risks and uncertainty can be continually evaluated in light of this new knowledge. The site can be chosen to limit transportation distances, to be away from existing communities, and to limit environmental impacts. The restrictions on appropriate geological siting are less than in the case of deep geological storage.

In the long term, this option provides the health, safety and environmental benefits arising from multiple engineered and geological barriers that isolate the used fuel. Safety is passive in the long term and resilient to environmental change, mitigating risks associated with institutional discontinuity and environmental disruption. Repackaging is not required in the long term, though one additional repackaging cycle will be required as compared to Option 1.

Risks and Uncertainty: Since this option requires institutional management in the near term, it is subject to the same risks as Options 2 and 3 over this period. If there is significant environmental change or a failure of institutional control prior to underground disposal, an unacceptable risk is posed to public health and safety and environmental integrity. However, during this time frame, critical societal disruption or environmental change is less likely than over the long-term, and management capacity is expected to be maintained.

In the very long term, adaptive phased management is subject to the same risks as deep geological storage, though these risks are expected to be less given the extended period of testing and confirmation prior to permanent disposal. Similar to Option 1, long term performance is somewhat uncertain as advance "proof of concept" is not scientifically possible given the long time frame. However, this uncertainty can be reduced substantially through the extended period of investigation, testing and confirmation prior to permanent disposal.

Like Options 1 and 3, community resistance may hinder siting. Transportation to the central site will be required, with attendant risks (though these are deemed to be small). In the short term, construction of the facility could produce adverse environmental impacts.

3.7.5 Social Issues

NWMO has been involved in an extensive engagement process with the general public and aboriginal community in Canada, which has brought to the fore many social issues associated with the management of used nuclear fuel. This section describes the process, the main areas of both debate and agreement, and insights from aboriginal peoples. In addition this section

outlines the values, ethics and objectives that Canadians have expressed are important, and how NWMO has incorporated these into its analysis.

3.7.5.1 The NWMO Engagement Process

NWMO undertook its study with the understanding that citizen views regarding the judgment of benefits and risks and the assessment of social implications of the various options were critical. While technical and scientific experts can assist in providing essential technical, environmental and economic analysis, this cannot be the only basis of decision making. NWMO has incorporated the "social and ethical considerations expressed by citizens as a fundamental building block for the study" (NWMO, Draft Report, 29).

The citizen engagement approach involved asking Canadians about the values and objectives they thought the options should be evaluated against, and then engaging citizens in assessing the options against those values and objectives. The option that is most responsive to these values and objectives will be judged to be the most socially acceptable.

The dialogue process was conducted over four stages: Conversations About Expectations; Exploring Fundamental Issues; Evaluating Management Approaches; and Finalizing the Study Report. The process sought to: identify the appropriate questions to be asked and key issues; confirm the methods to be assessed; evaluate the options on the basis of risk, costs and benefits; and, design the management structure and implementation plans for the options.

Dialogue initiatives have included:

- A scenarios exercise
- Commissioned papers
- A workshop with technical and scientific specialists from a wide range of fields
- A national citizens dialogue on values
- Public information and discussion sessions
- Dialogues designed and conducted by Aboriginal Peoples
- A roundtable of experts on ethics
- A roundtable session with public opinion leaders in the communities that currently host interim used nuclear fuel management
- E-dialogues

3.7.5.2 Main Areas of Debate

NWMO discovered that Canadians have important differences of opinion on fundamental questions related to nuclear waste management. The three main differences related to views on:

the future role of nuclear electricity generation, the sufficiency of current knowledge for decision making, and the vision of the future for which plans should be made.

With respect to the continued role of nuclear power, some citizens held the view that if the costs and benefits were evaluated on a life cycle basis, the technology would be abandoned. Others thought that a life cycle evaluation would lead to a continued role for nuclear power, while some suggested that since waste exists, a mechanism for managing it must be developed regardless the future use of the technology. NWMO has not examined the appropriate role for nuclear power, and suggests that future decisions regarding this form of generation should be subject to their own assessment and public process.

There was divergent opinion as to whether the large body of existing knowledge is sufficient to support decision making now, given the uncertainty that inevitably arises due to the long time period during which the fuel must be managed.

Finally, perspectives varied as to what the future is likely to look like. For example, some Canadians might consider future institutional collapse to be likely, while others might believe that future advances in science and technology will lead to better ways of managing the waste than presently exist.

3.7.5.3 Main Areas of Agreement

Despite the three main areas of difference, there was considerable common ground on what values, ethics and objectives should inform the selection of the preferred approach. The following tables describe these values and ethics (NWMO, Draft Report, pp. 43-480):

Table 3.7.2 - Citizen Values Which Should Inform Selection of a Preferred Approach (NWMO)

Value	Description
Safety from harm	An overarching requirement. First and foremost, human health and the environment must be as safe as possible from harm, now and in the future.
Responsibility	We need to live up to our responsibilities to ourselves and to future generations, and deal with the problems we create.
Adaptability	We need to build in capacity to respond to new knowledge.
Stewardship	We have a duty to use all resources with care and to conserve, leaving a sound legacy for future generations.
Accountability and Transparency	Governments are ultimately accountable for the public good concerning safety and security, but must involve citizens, experts and stakeholders in any decision-making. Honour and respect must be shown for all.
Knowledge	We need to continue to invest in informing citizens, and in increasing knowledge, to support decision-making now and in the future.
Inclusion	The best decisions reflect broad engagement and many perspectives; we all have a role to play

Source: NWMO Draft Report, pp. 43-45

Table 3.7.3 - Ethical Principles Which Should Inform the Selection of a Preferred Approach

Principle	Description
Respect for Life	In all its forms, including minimization of harm to human beings and other sentient creatures; Respect for People and Cultures.
Respect for Future Generations	Of human beings, other species, and the biosphere as a whole.
Justice	Across groups, regions and generations; fairness – to everyone affected and particularly to minorities and marginalized groups.
Sensitivity	To the differences in values and interpretation that difference individuals and groups bring to the dialogue.

Source: NWMO Draft Report, pp. 45-46

Table 3.7.4 - Objectives Which Should Inform the Selection of a Preferred Approach

Objective	Description
Public Health and Safety	To ensure public health and safety.
Fairness	To ensure fairness (in substance and process) in the distribution of costs, benefits, risks and responsibilities, within this generation and across generations.
Worker Health and Safety	To ensure worker health and safety.
Community Well-being	To ensure community well-being.
Security	To ensure security of facilities, materials and infrastructure.
Environmental Integrity	To ensure environmental integrity.
Economic Viability	To design and implement a management approach that ensures economic viability of the waste management system while simultaneously contributing positively to the local economy.
Adaptability	To ensure a capacity to adapt to changing knowledge and conditions over time.

Source: NWMO Draft Report, pp. 46-47

3.7.5.4 Special Insights from Aboriginal Dialogues

Several of the observations and insights from the aboriginal dialogues were consistent with those gathered during the broader NWMO public dialogue. Commonalities include: the highest priority was concern for the safety and security of people and the environment; the need to reduce energy use in general and nuclear energy use in particular, and to evaluate nuclear technology on a full life-cycle basis; the rejection of the idea of waste importation from other countries; and, a belief in the need for more research, and the development of alternative energy sources and storage containers.

In addition, a number of observations and insights were made arising from the particular history, experience, and concerns of Canada's aboriginal community. The issue of consultation with aboriginal peoples is a complex legal issue based on the Canadian constitution, and there was disagreement as to whether the NWMO process constituted "consultation" in this respect. Further, the aboriginal community expressed concern that the costs, benefits and risks related to

nuclear waste management be fairly distributed and, in particular, that northern rural dwellers are not disadvantaged vis-à-vis urban dwellers.

Due to historical experience, some aboriginal people were deeply distrustful of government, the nuclear industry, power utilities, the NWMO, and the dialogue process. Others expressed willingness to work towards building respect while contributing to finding a strategy for dealing with the waste issue. Additionally, participants stressed the need to recognize explicitly aboriginal rights, treaties and land claims, as well as traditional wisdom and knowledge.

The aboriginal community was divided on the issue of whether the community should bear any responsibility for managing nuclear fuel, as aboriginal peoples were not consulted when the decision to generate nuclear power was made. Despite concerns about the NWMO process and its legal implications, there has been a consistent call for an effective, ongoing engagement program with information that is culturally and linguistically appropriate.

3.7.5.5 NWMO Incorporation of Social Concerns into Decision Making

NWMO incorporated the common ground identified through the dialogue process by establishing an evaluation framework that included each of the eight objectives identified above. Each option was rigorously assessed against this framework, using multi-attribute analysis and in terms of benefits, costs and risks. Based on the commentary received through the engagement process with the general public and with aboriginal peoples, NWMO introduced the fourth option (Adaptive Phased Management) into their study which had not been originally specified by the NFWA.

Though the three technical options were each well understood and technically credible, NWMO found that the greatest challenge was in the appropriate implementation of the management approach rather than finding a technical method. None of the three technical options specified by the NFWA perfectly addressed the values and objectives that citizens emphasized as being important. As a combination of elements of all three options, Adaptive Phased Management builds on the strengths of each approach and better meets the criteria identified through the citizen engagement process.

Since this approach best responds to the values and objectives put forth by Canadians, it is the option recommended by the NWMO. This option is thought to best serve the "primary objectives of safety – the protection of humans and the environment – and fairness to this and future generations." (NWMO, Executive Summary of Draft Report)

Updated Information:

In November, 2005, the NWMO issued "Choosing a Way – The Future Management of Canada's Used Nuclear Fuel", the report to the federal government it was required to make by November 15, 2005. The report presents the results of its work to date and recommends the Adaptive Phased Management approach, with the rationale that:

- It commits this generation of Canadians to take the first steps now to manage the used nuclear fuel we have created
- It employs the best available science and technology in pursuit of safety and security
- It provides for centralized containment and isolation of used nuclear fuel deep underground in suitable rock formations, with continuous monitoring and opportunity for retrievability and,
- It allows sequential and collaborative decision-making, providing the flexibility to adapt to experience and societal and technological change.

The covering letter concludes with:
"We are confident that we have the necessary knowledge to begin to meet society's ethical obligations today and for the future. **We are convinced that now is the time to act decisively.**"

3.8 Integrated Gasification and Combined Cycle (IGCC) – Overview and Status

This section provides an overview of the Integrated Gasification Combined Cycle (IGCC) technology and an assessment of IGCC's status, in particular, its technological maturity to be a supply option for Ontario.

3.8.1 Key Findings

- Integrated gasification of IGCC coverts organic feedstock (e.g., coal, biomass, etc.) to a synthetic gas which is burned in a conventional combined cycle plant; being a two-stage generation, IGCC is capable of achieving high efficiencies, in the range of 40-45%
- Use of multiple gasifiers allows IGCC to achieve high capacity factors because of the ability to do maintenance without plant shutdown
- Syngas has about 25% of the heating value of natural gas – meaning much more mass flow through the turbines is required
- IGCC uses a variety of means to reduce contaminant emissions: filters and water washing are used to remove particulates; mercury and other hazardous air pollutants can be removed by absorption using activated carbon; sulphur removal requires cooling the gas to below 100° C; and water/steam injection reduces NOx emissions
- Costs of emission controls are expected to decline by 90% as IGCC becomes widespread
- Dramatic reductions in carbon dioxide emissions are likely to become technically achievable and economically viable through sequestration; sequestration via enhanced oil recovery is already established, and can produce a revenue stream as well
- IGCC is cheaper (without sequestration and assuming an 80% capacity factor) than natural gas combined cycle for gas prices above $5 U.S./MMBtu and coal at $1.5U.S./MMBtu, but plant cost is 20-30% more than for pulverized coal plants
- Carbon dioxide capture and sequestration would add approximately 30 per cent to the capital cost and about 40 per cent to the cost of power, making it not competitive with natural gas at forecast prices
- Individual components of IGCC plants (except for carbon sequestration) have been widely used with petroleum residuals as fuel; little experience exists with integrated systems operating on coal and therefore it is not yet considered mature, reliable and economic
- Large-scale coal gasification with sequestration is not considered feasible or economic at this time
- It is more feasible to plan for small-scale gasification from biomass or waste for the to a 2015 timeframe, subject to ongoing monitoring of IGCC and sequestration experience in the U.S.

3.8.2 Introduction

In essence, IGCC is a gas-fired power generation technology that converts coal (or some other feedstock) to gas and uses the gas, rather than the coal, for thermal combustion. A combined cycle plant is one that captures the heat loss from the initial cycle (a gas turbine) and utilizes that heat in a second cycle (a steam turbine) that produces additional electricity.

3.8.3 IGCC Technology Basics

An IGCC plant takes a feedstock, usually coal or petroleum coke, and gasifies it to produce syngas, to fuel a combined cycle plant. Some of the steam from the combined cycle plant is used in the gasification process. Removal of particulates prior to combustion is necessary to prevent erosion of the combustion turbine blades. Removal of sulphur is also done in the pre-ignition stage, where it is more efficient and cost effective than cleaning the flue gases resulting from combustion. Since the gasifier operates at high pressure, the CO_2 produced in the gasification process can also be efficiently removed prior to combustion. Again, this can be more cost effective than attempting removal from post-combustion flue gases in a conventional plant.

Syngas is predominately a hydrogen (H_2) and carbon monoxide (CO) mixture and usually has about a quarter of the heating value of natural gas, which is largely methane (the heat value difference is 1026 BTU/ft^3 versus 200 to 300 BTU/ft^3). Due to its lower heating value a larger mass flow through the turbines is required to develop a given amount of energy. This mass flow dictates different sizing of piping and larger turbine exhaust ducts than would be required for a natural gas fueled plant.

The efficient operation of an IGCC requires integration of the heat flows in the gasification, cleaning and combustion phases. According to CERI, and depending on the level of integration, IGCC plant designs are capable of achieving 40% to 42% efficiencies. A high of 45% may be obtained with advanced (or hot) gas cleaning processes.[1]

Achieving high availability requires having multiple process streams so that maintenance can be done without shutting down the complete operation of the plant. The capacity factor is limited to about 82% without a spare gasifier.[2]

[1] See the CERI Report in Part 4.3.
[2] "Cost Comparison IGCC and Advanced Coal" S. Dalton (EPRI) 2004 (www.climatevision.gov/pdfs/coal_roundtable/dalton.pdf).

3.8.4 State of IGCC Development

A number of IGCC plants of around 250 MW are operating in Europe and the United States. These include:[3]

- Buggenum, Netherlands, 253 MW coal, 2000
- Shell Pernis Netherlands, 120 MW cogeneration, refinery bottoms
- Elcogas, Puertollano, Spain, 298 MW, Prenflo gasifier, 50:50 coal:petroleum coke, 1998
- Polk, Tampa, USA, 250 MW coal and/or coke, 2001
- Wabash River, USA, 262 MW, coal and/or coke, 2001
- Sarlux, Italy, 551 MW, petroleum coke
- Negishi, Japan, 342 MW, asphalt, 2003
- Pino Pine, USA, 107 MW, fluidized bed gasifier, 1998

In addition to these operating plants, design studies also exist for larger plants in the 600 MW and 1,000 MW range.[4]

A variety of IGCC gasification processes is available.[5] Since IGCC units operate under pressure, fuel handling is more complicated than for conventional coal-fired generating stations. Gasifiers are limited by size considerations to about 250 MW and appear to require substantial maintenance. The use of multiple gasifiers, however, is possible.

Despite these considerations, gasification technology is considered fully proven and commercially available as a supply of gas (i.e. not electricity), with 385 gasifiers in operation at 117 projects around he world.[6] However, IGCC applications have mostly used petroleum residuals rather than coal. Current technology can conserve 80-90% of the chemical combustion energy in the feedstock material.

3.8.5 Environmental Considerations

Particulate removal in IGCC plants is performed by filters and water wash. Mercury (Hg) and other hazardous air pollutants (HAPs) can be removed by absorption on an activated carbon bed. Sulphur removal requires cooling the gas below 100° C. High temperature and pressure

[3] See www.clean-energy.us/success.htm.
[4] "A Large Coal IGCC Power Plant" Amick, Geosits, Herbanek, Kramer and Tam. 2002 (www.bechtel.com/PDF/BIP/22008.pdf).
[5] Global E Gas (ConocoPhillips), Texaco (C-T soon to be GE), Shell and Prenflo.
[6] "National Gasification Strategy- Gasification of Coal & Biomass as a Domestic Gas Supply Option" Rosenberg, Walker and Alpern. 2005. (www.innovations.harvard.edu/showdoc.html?id=4972).

systems are also available. NO_x control is via water/steam injection and keeps NO_x emissions below 100 ppm.[7] All these emission control technologies are well proven.

The CO_2 capture in an IGCC plant would take place prior to burning while the gas is under pressure (~ 60 bar). This is done by adding water-gas phase shift reactors and physical absorption processes that are commercially proven in industrial applications. The table below gives expected emission rates. CO_2 removal in other generation technologies would require treating the flue gas using either chemical absorption or absorption membranes. These technologies are not well demonstrated, although Dolf Gielen considers them more proven than many renewable supply options or advanced nuclear reactors. The initial cost estimates quoted by Gielen are $(US) 30 per ton from gas fired plant, and $45 from conventional coal fired plants[8].

Cost reductions for IGCCs due to learning effects are still expected to be substantial (of the order of 90% of the cost of emission controls) if the technologies get widespread use. Any cost advantage to IGCC over other technologies when brought to a comparable environmental performance level by the use of CO_2 sequestration, is dependant of the quality of coal used. IGCC will be lower in cost when using high quality coals and, according to one source, the same as other technologies if using sub-bituminous coals, and possibly higher in cost if lignite is used.[9]

Table 3.8.1 - Carbon Dioxide Emissions with IGCC

Technology	CO_2 emissions (kg CO_2/kWh)
IGCC with CO_2 removal	0.10
IGCC (no CO_2 removal)	0.68
Conventional Coal (no CO_2 removal)	0.81
Natural Gas CC (no CO_2 removal)	0.37

Source: Dolf Gielen

There is a variety of technologies proposed for CO_2 sequestration, including aquifers, deep ocean storage, and oil and gas fields, either when depleted or to assist recovery of the oil and gas resources. Of these, enhanced oil recovery (EOR) is an established technology. Enhanced gas recovery is not yet established. These methods have the advantage of producing additional revenue streams for the IGCC plant, hence offsetting some of its additional costs. Oceanic storage is the most controversial option. In any of these methods, transportation cost is a critical component. EPRI (the Electric Power Research Institute) estimates CO_2 transportation and sequestration to cost $(US) 5/metric tonne of CO_2.

[7] See CERI Report in Part 4.3.
[8] Dolf Gielen, "Uncertainties in relation to CO_2 capture and sequestration. Preliminary results". Dolf Gielen, IEA. 2003 (www.iea.org/textbase/papers/2003/gielen.pdf)
[9] Holt, Booras and Todd, "A summary of recent IGCC studies of CO_2 capture and sequestration" Holt, Booras and Todd, 2003. (www.gasification.org/Docs/2003_Papers/31HOLT_paper.pdf)

Sequestration opportunities do exist in saline formations in southwest Ontario, with a combined capacity of some 1,100 Mt of CO_2.[10] Depending on where the generating plants were built, some pipeline infrastructure would be required.

Thus while each individual component of an IGCC plant, with the exception of carbon capture and sequestration, is in widespread use, the integrated package, operating on coal, appears only to have been demonstrated at a few facilities around the world.

3.8.6 IGCC Adoption

While conventional coal is being proposed at dozens of sites in the U.S. for 2008 –2012 (according to EPRI), there is so far only one IGCC project underway.[11]

IGCC appears to be perceived as having insufficient operating experience. A recent (U.S.) survey of the perceived risks involved showed that the highest risks included the high capital costs, excessive downtime, lack of standardization, lack of state and national policies, regulatory approval and financing.[12]

For IGCC to be perceived as mature, reliable and economic, more commercial experience needs to be gained through deployment. However, to attract the investment needed for deployment, the technology needs to be perceived as commercially mature, reliable and economic. In the U.S. there is an initiative, based at Harvard University, to introduce federal legislation to address this dilemma, through third-party covenant financing and regulatory initiatives.[13] However, this has not borne any fruit yet. Other groups, such as the Gasification Technologies Council, the IGCC Coalition and the Coal Utilization Research Council, are also discussing incentives for IGCC or advanced coal use.[14]

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[10] "CO_2 sequestration in Ontario, Canada. Part I: Storage Evaluation of Potential Reservoirs." *Energy Conversion and Management*, Volume 45, Issue 17, October 2004, Pages 2645-2659, http://www.sciencedirect.com/science?_ob=JournalURL&_cdi=5708&_auth=y&_acct=C000050221&_version=1&_urlVersion=0&_userid=10&md5=2b1146f594aa18a4d2ea20a4b02ec486&chunk=45#45.

[11] On Sept 29, 2005 American Electric Power announced that it has contracted with Bechtel and GE to provide preliminary engineering and design for a 629 MW IGCC plant, that it is due in service in 2010.

[12] "Climate Vision Risk Framework for Advanced Clean Coal Plants – Risks and Challenges" D. Berg (DOE) 2004. (www.climatevision.gov/pdfs/coal_roundtable/berg.pdf).

[13] See "Deploying IGCC In This Decade …." Rosenberg, Alpern and Walker. Harvard University. 2005. (bcsia.ksg.harvard.edu/publication.cfm?ctype=paper&item_id=462).

[14] www.gasification.org, www.igcccoalition.org, and www.coal.org.

3.8.7 IGCC Costs

According to CERI, IGCC capital costs (without CO_2 capture) are in the range of US$1,200 to US$1,400/kW, which is about 20% to 30% more than pulverized coal generating costs. The costs of CO_2 capture and sequestration from new IGCC plants add 40% to 50% to the cost of electricity, compared to 80% to 90% for new conventional coal plant.[15]

The table below contrasts the CERI estimates of the cost and efficiencies with estimates from a recent paper by EPRI. [16]

Table - 3.8.2: IGCC Costs

(U.S.$ 2003)	**CERI (EIA)**	**EPRI (Spare/No Spare)**
Overnight cost* ($/kW)	1,402	1,610/1,490
Fixed O&M ($/kW-yr)	34	56/52
Variable O&M ($/MWh)	2.6	0.9
Heat Rate (Btu/kWh)	8,309	8,630

* Overnight cost is a term used to show capital cost without capitalized interest, as would be the case if a plant could be constructed in one day (hence "overnight").

Source: CERI (EIA), EPRI

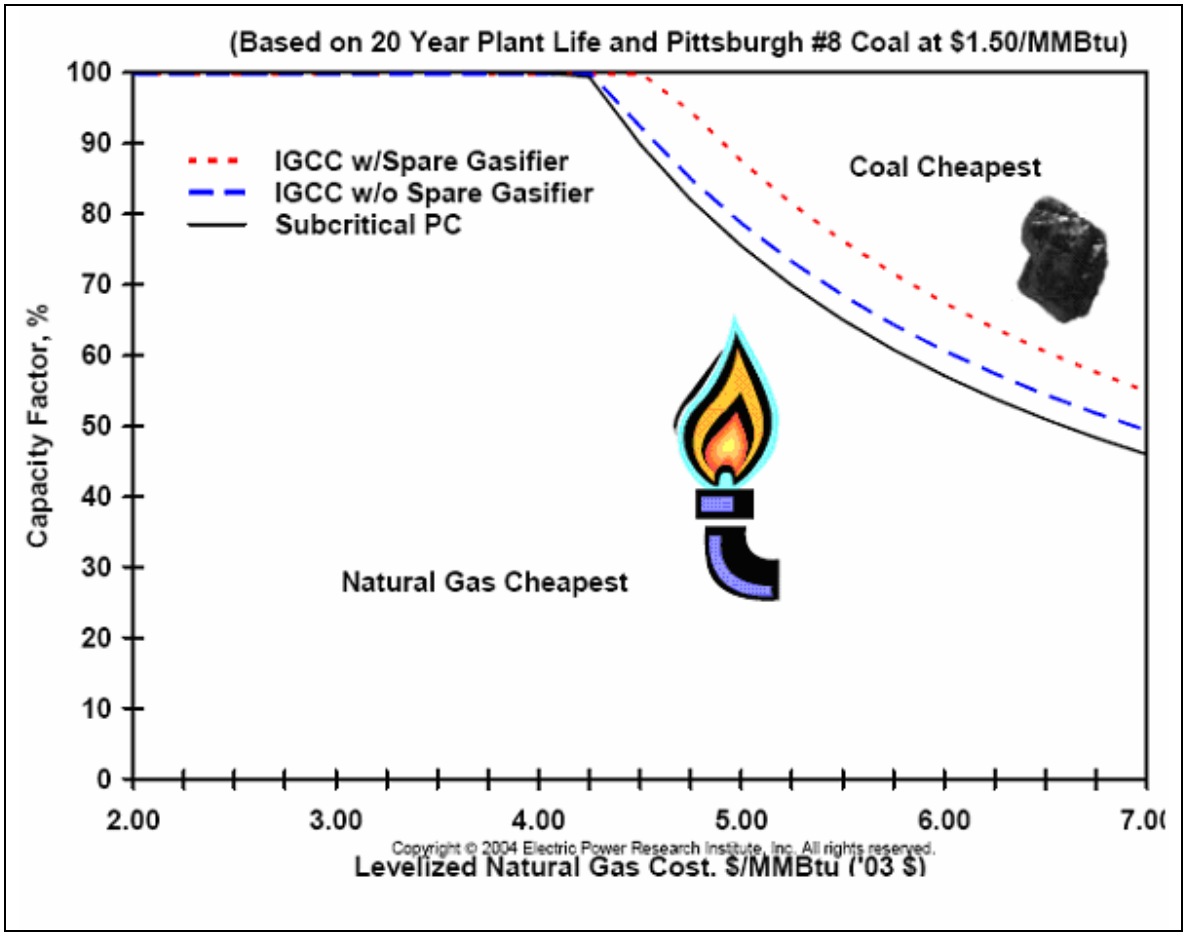
IGCC being a reasonably new technology, these cost estimates must be considered to be more uncertain than for established technologies. Capital cost ranges of -15 per cent to + 35 per cent would be appropriate.

The economics of IGCC versus gas fired plants naturally depend on the relative prices of gas and coal and the availability of the IGCC. The figure below shows EPRI's breakeven analysis, assuming coal at $1.5 (U.S.)/MMBtu. It shows that gas prices have to be above US$5.00/MMBtu for coal to be cheaper (assuming an 80% capacity factor).

EPRI has also analyzed the costs of CO_2 removal from a variety of new fossil fuel power plants. The results are shown on the next table. The table confirms the analysis above that the cost of gas and new coal, without CO_2 capture, is similar when gas is priced at US$5.00/MMBtu. However, with CO_2 capture, the breakeven gas price falls to about US$3.50 /MMBtu.

[15] See "A summary of recent….." Op. Cit, EPRI uses transportation and sequestration costs of $5/Metric tonne.
[16] See "Cost Comparison IGCC and Advanced Coal" S. Dalton (EPRI) 2004 (Op. Cit.).

Figure:3.8.1 - Breakeven Capacity Factor and Fuel Cost for Natural Gas vs Coal



Source: EPRI; NB: "Subcritical PC" refers to a conventional coal-burning generating plant

Table 3.8.3 – Costs of Carbon Dioxide Removal from a New Fossil Fuel Power Plant – an EPRI Estimate

$/MWh Without Capture	$/MWh With Capture	$MWh With Capture & Sequestration	Avoided Cost $/Metric Ton of Carbon
36.5	59.0	61.1	267
47.3	72.8	74.9	300
48.6	61.0	65.3	88
45.0	75.4	79.8	174

Notes: Pittsburgh #8 coal at $1.50 MBtu delivered
Natural Gas at $3.50 and $5.00/MBtu
Cost of CO_2 transportation and sequestration $5/metric ton of CO_2
Plant Size with CO_2 removal – 450 MW
Capacity Factor 80% for all technologies

Source: EPRI

3.8.8 Recommended Role in Ontario/Portfolios

The immediate deployment of IGCC, while technically feasible, involves significant technological and financing risks due to the relative immaturity of the concept.

It can be anticipated that by 2015 current initiatives in the U.S. will have demonstrated the efficacy of IGCC so that IGCC might become a viable option for Ontario. While the opportunities for sequestration in the Ontario seem limited, it is possible that CO_2 capture and sequestration techniques may also be available about this time. IGCC developments in the U.S. should therefore be carefully monitored.

The potential for IGCC adoption in Ontario can be assessed in two ways. If continuing high gas prices are forecast, then IGCC may well be an economic source of supply, utilizing the large reserves of coal with low environmental impacts. Alternatively, if IGCC is thought of as a hedge against high gas prices, its use in portfolios with high gas usage would then be appropriate.

Being a coal-fired plant, an IGCC raises the issues of the relative costs of transport of coal versus electricity. The infrastructure exists to bring Appalachian coal to southern Ontario. Since there may be problems firming up transmission capacity to bring power from a plant in the area of the mine mouth, siting such a plant using Appalachian coal in southern Ontario would probably be economic. For western Canadian coal, it may make sense to piggyback on potential east-west transmission that would accompany a waterpower purchase from Manitoba. Such a plant would be sited in Saskatchewan or Alberta, close to the source of the coal, although using low quality western Canadian coals would probably have an adverse effect on the economics of such a proposal.

3.9 Context Background for Natural Gas Prices

This section provides a brief outline of the current context for forecast natural gas price availability, deliverability and price by addressing two main subjects. The first is the broad natural gas pricing situation in North America, Canada and Ontario. The second subject is information relating to the particular capacity issues surrounding the use of large amounts of natural gas for power generation in the GTA/Golden Horseshoe area, and the gas price forecast used in developing the supply mix advice.

3.9.1 Key Findings

- Forecasting future natural gas prices is very difficult and uncertain, especially given the current tight supply environment in natural gas markets, uncertainty regarding liquefied natural gas (LNG) infrastructure and coalbed methane, and Ontario's plan to replace coal-fired generation
- Canadian gas reserves declined by 2% in 2003, which led to higher prices, but gas experienced a strong price recovery in 2004 even though production increased only slightly with a 43% increase in the number of wells drilled
- The most current National Energy Board estimate (2004) for the ultimate potential of natural gas in Canada, including proved reserves and undiscovered conventional resources (coalbed methane, tight gas and shale gas), is 575 Tcf, which is about 77 years of natural gas supply at 2002 levels of production
- OPA has selected the natural gas price forecast produced by Sproule— a recent forecast by an independent forecasting entity, for use in the preparation of the supply mix advice that projects that prices will decline from current levels to slightly less than $8/MMBtu by 2010 and remain close to this level until 2025. Other forecasts were reviewed and are generally consistent with Sproule's
- The OEB's Natural Gas Electricity Interface Review (NGEIR) reported that gas-fired generators would become the largest class of gas consumers in the province if all current coal-fired generation were replaced with natural gas, consuming more gas than all natural gas residential customers in the province combined
- The growth of natural gas-fired generation demand is not likely to conform to a steady load growth profile and hence there is likely to be additional demands on the delivery systems that have not previously been present
- The cost of infrastructure investment needed to accommodate such an expansion of gas-fired generation in Ontario could reach $815 million, depending on the increase in gas-fired generation, the location of the generators and their gas storage and deliverability requirements

3.9.2 Introduction

Gas price forecasting in the current tight supply environment is especially difficult because behavioural considerations come into play in addition to the usual technical factors. These factors include gas conservation, fuel switching and storage capacity. The technical factors are themselves complex and assumptions must be made in order to provide the context for modelling gas use, supply/demand balances, and pricing.

In cases where the gas delivery system, including storage capacity, must be augmented significantly to provide the large quantities of gas required by electricity generation, there is concern on the part of other non-generation gas users that the additional infrastructure costs, and to some degree the additional market force costs, do not fall on them. This discussion is still active and unresolved and hence the final gas prices at the consumer level, either generator or non-generator, are unresolved.

The basis for most of this section is a report by Natural Resources Canada (NRCan) entitled "Canadian Natural Gas – Review of 2003 & Outlook to 2020". It was issued in December 2004. This document was chosen for a number of reasons:

- It draws together in a cohesive and well considered way, the work of the Energy Information Administration (EIA) in the United States (whose work is thorough and considered to be relatively unbiased) with the work of the National Energy Board (NEB), Stats Canada, CERI and other reputable expertise based in Canada
- Its information has been reviewed for accuracy and consistency and presented in a tight, clear format
- It makes extensive use of graphics to provide information in a useful way. (Many of the graphics have been transferred to this report)

Unfortunately, the NRCan forecast did not capture the effects on prices from Hurricane Katrina's recent destruction, but if we consider the warnings that gas prices can be expected to be extremely volatile in the existing tight supply situation, then Katrina is only a demonstration of how that volatility arises.

The second part of the section, dealing with gas delivery and price issues in Ontario related to the use of gas for electricity generation in and around the Golden Horseshoe, is derived from an examination of a large number of submissions on the subject to the Ontario Energy Board and others.

3.9.3 Recent North American Gas Supply Situation

3.9.3.1 Demand/Supply

The natural gas market in Canada is tightly integrated with the market for the entire North American continent by pipelines, marketing arrangements and supply sourcing. Prices reflect both Canadian and U.S. demand. Beginning in mid-2000, North American prices moved up to a new higher range with Alberta ("AECO" – the price at a "hub", or location where many pipelines interconnect, in Alberta where the pipelines are largely owned by the former Alberta Energy Company – part of today's Encana) prices averaging $5.45/Gigajoule[1] (GJ) between mid-2000 to the end of 2003. In 2002 prices were slightly lower at $3.83/GJ. At the beginning of the 2002-2003 heating season, the prices rose to $5.25/GJ and increased to $8.45/GJ in March, as a result of colder weather, concern about natural gas production and increases in world crude oil prices.

In 2003 Alberta prices averaged $6.31/GJ, an increase of 65% above 2002 levels, due largely to declining natural gas production rates, low storage levels, a strengthening industrial economy, increased Canadian demand and strong crude oil prices. Particularly worrisome were the facts that, despite increased drilling activity, production could not be increased, and natural gas demand was growing in Canada at the same time it was decreasing in the U.S. The differences reflected the differing weather experienced in the two countries and the fact that the U.S. increased Liquefied Natural Gas (LNG) imports which displaced purchases from Canadian sources.

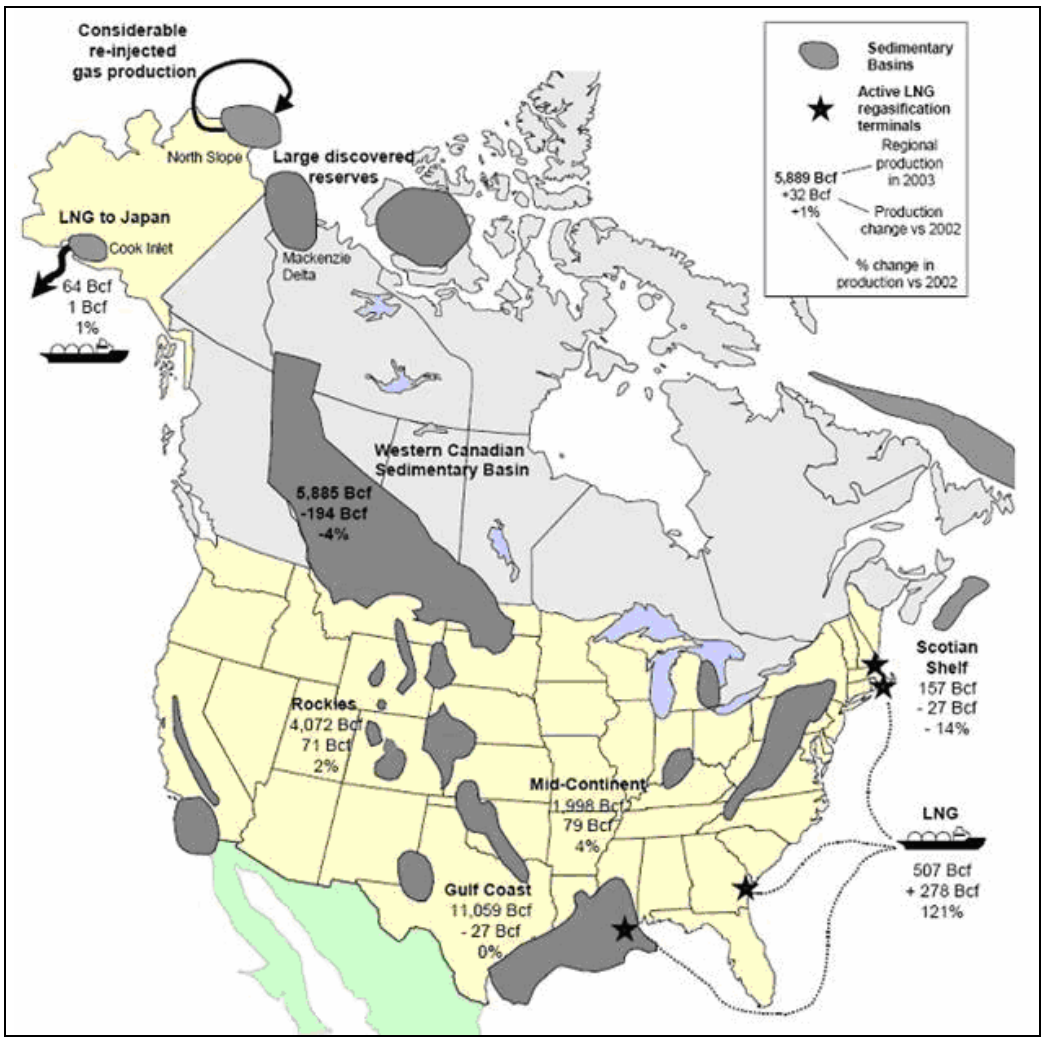
Gas storages were drawn down substantially over the 2002-2003 winter, creating market pressure on prices. The strong price recovery in 2003 has tended to stay with us and it now appears that prices have moved permanently into the US$4.00 to US$6.00/MMBtu[2] range, all a reflection of the ongoing factors that drove the 2003 prices up. Weather is a major factor in gas prices and regions with colder winters tend to have higher gas prices.

Since many industrial users and power generators can switch between gas and oil as fuel sources, world crude prices also have a significant effect on gas prices. Gas reserves are a powerful indicator of future production. As such, changes to reserves will lead to changes in the market price of gas. In 2003, reported U.S. gas reserves rose by 2%; Canadian reserves declined by 2%. The short-term outlook is for continuing tight supply-demand balances, high world crude oil prices, and relatively strong economic growth. Prices in the first seven months of 2004 averaged $6.48/GJ. Increased drilling in 2004 provided some relief in the form of slightly increased production, but that was the result of a 43% increase in the wells drilled.

[1] Unless otherwise indicated, all $ amounts are stated in Canadian currency
[2] A GJ (gigajoule) is roughly equal to a million Btu (MMBtu), British thermal units.

The North American sources of supply are shown in the map below.

Figure 3.9.1 – Natural Gas Supply Sources – 2003



Sources: EIA, StatsCan, NRCan estimates

Figure 3.9.1 portrays the supply values in place in 2003. It is noteworthy that in 2003 net LNG imports by the U.S. increased by 121%, although they were still only about 2% of the total U.S. supply. The importance of LNG is expected to increase as an incremental supply to North America.

The following tables provide a numerical insight into the changes that occurred in gas supply in the 2002-2003 period.

Table 3.9.1 – North American Gas Supply in 2003

	2003 (Bcf)	2002 (Bcf)	Change 02 vs 03	% Change 02 vs 03
Gulf Onshore[1]	6,798	6,637	161	2%
Gulf Offshore[2]	4,261	4,449	-188	-4%
Total Gulf	11,059	11,086	-27	0%
U.S. Midcontinent[3]	1,988	1,910	79	4%
U.S. Rockies[4]	4,072	4,000	71	2%
Other US	1,949	1,968	-18	-1%
Total U.S. Production	**19,068**	**18,964**	**105**	**1%**
Western Canada[5]	5,885	6,079	-194	-3%
Scotian Shelf	157	184	-27	-14%
Total Canada Production[6]	**6,042**	**6,263**	**-221**	**-4%**
Total N.A. Production	**25,110**	**25,226**	**-116**	**0%**
U.S. Net LNG Imports	443	165	278	169%
U.S. Net Mexican Imports	-333	-261	-72	27%
U.S. Supplementals[7]	65	68	-3	-4%
Total N.A. Supply	**25,285**	**25,198**	**88**	**0%**

Sources: EIA, StatsCan, NRCan estimates. Notes: (1) AL, LA, MS, TX (2) Federal Offshore Gulf of Mexico (3) KS, OK (4) CO, NM, UT, WY (5) Includes minor Ontario production. (6) Canadian production is marketable gas plus reprocessing shrinkage. (7) Synthetic natural gas, propane-air, refinery gas, biomass gas, air injected for stabilization of heating content, and manufactured gas commingled and distributed with natural gas.

Table 3.9.2 – North American Drilling Activity in 2003

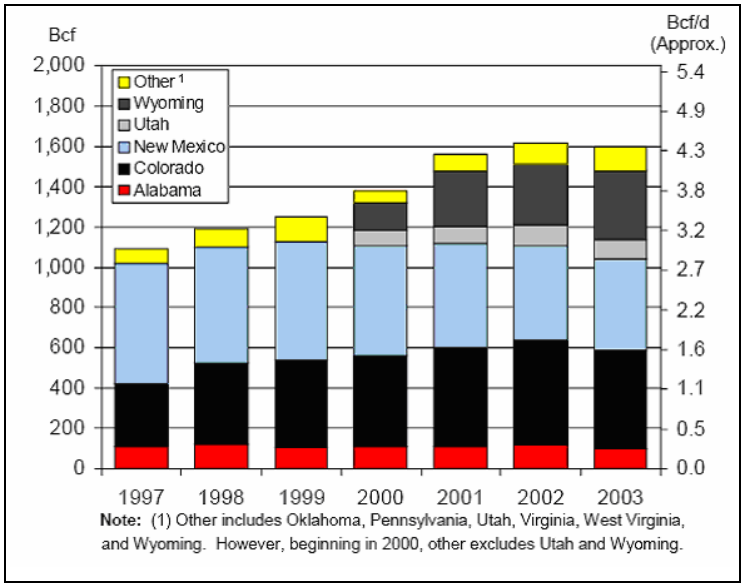
	2003	2002	Change 03 vs 02	% Change 03 vs 02
Active Oil & Gas-Directed Rigs: 1				
Gulf Onshore 2	523	402	121	30%
Gulf Offshore 3	105	109	-3	-3%
Total Gulf	629	511	118	23%
U.S. Midcontinent 4	142	99	43	43%
U.S Rockies 5	174	123	52	42%
Other US 6	107	98	10	10%
Total U.S	**1,052**	**830**	**222**	**27%**
Active Gas-Directed Rigs: 7				
Total US	**871**	**673**	**197**	**29%**
Canadian Gas Wells Drilled:				
Shallow 8	10,982	6,804	4,178	61%
Deep 9	2,950	2,266	684	30%
Total Canada 10	**13,932**	**9,070**	**4,862**	**54%**

Sources: Texas RRC, Baker Hughes, Daily Oil Bulletin. Notes: (1) Number of wells not available, so average total weekly oil and gas-directed rig count used. (2) AL, LA, MS & TX onshore. (3) AL, LA, MS & TX offshore (4) AR, KS & OK. (5) CO, NM, UT & WY. (6) Remaining U.S. (7) Average total weekly gas-directed rig count. (8) Alberta West of 4th meridian gas wells, plus Saskatchewan gas wells. (9) Alberta W5 and W6 meridian gas wells, plus all British Columbia gas wells. (10) Total number of Western Canadian Gas Wells

Total North American natural gas production decreased 116 Bcf, for a change of less than 1% from 2002. Canadian production decreased by 221 Bcf or 4%, with most of that decline in western Canada.

In the U.S., coalbed methane (CBM) is a well established source. The largest known concentrations occur in the Rocky Mountains of Wyoming, Montana, northern New Mexico, southern Colorado, eastern Utah, and Alabama. Large deposits of CBM are known and being developed in the Powder River Basin, Uinta Basin, Piceance Basin, and Raton Basin.
The following figure portrays the data in graphical form.

Figure 3.9.2 – U.S. Coalbed Methane Production



Sources: EIA, reproduced in NRCan

Canadian CBM is moving from exploration to development mode. Production as of September 2004 is estimated to be 70 MMcf/d. Table 3.9.3 summarizes CBM activity in Canada.

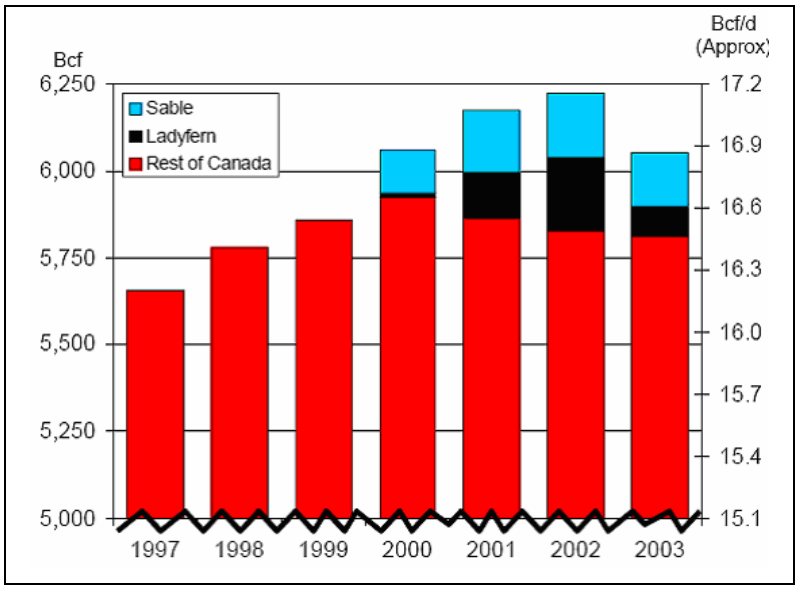
Table 3.9.3 – Summary of CBM Activity in Canada

British Columbia			**Alberta Plains**		
Coal Zone	**Projects**	**%**	**Coal Zone**	**Projects**	**%**
Gates	11	42%	Manville	39	43%
Elk	7	27%	HorseshoeCanyon	41	46%
Fernie	1	4%	Ardley	10	11%
Other	7	27%			
Total	**26**	**100%**	**Total**	**90**	**100%**

Source: Perspective Consultants Inc. reproduced in NRCan

Total Canadian natural gas production declined 4% in 2003, or about 0.5 Bcf per day.

Figure 3.9.3 – Canadian Natural Gas Production



Sources: StatsCan, CNSOPB, BC Oil and Gas Commission, NEB, NRCan estimates

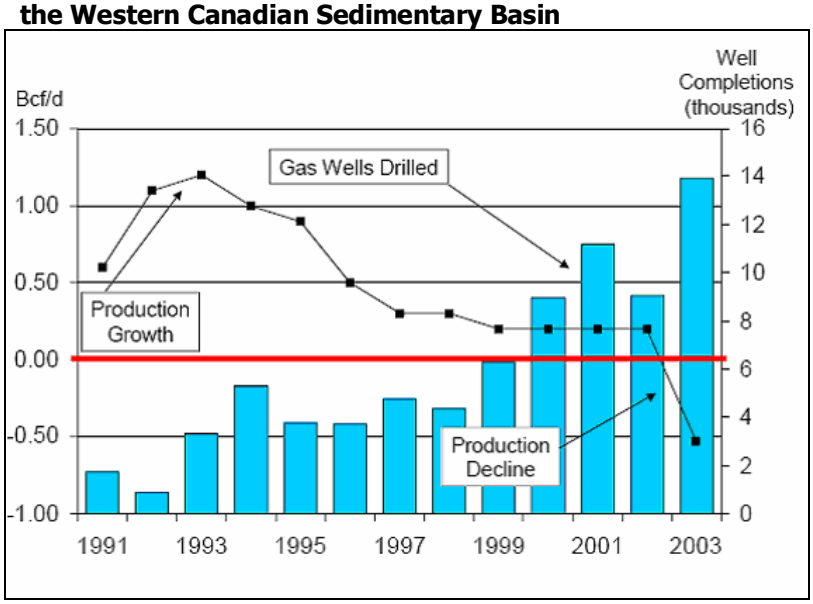
It is worth noting that a high percentage of the Sable Island Gas (79% in 2003) was exported to the U.S., with the remaining 21% consumed in Atlantic Canada. Moreover, the Sable gas production peaked in December 2001 and is now in decline. New drilling in the area has been relatively unsuccessful. Forecasted production for the areas now in production is much smaller by the end of the next decade.

In western Canada the situation is shown in Figure 3.9.4.

In 2003, almost 14,000 wells were drilled in the Western Canadian Sedimentary Basin (WCSB), setting a new record. This is an average of over 38 wells per day.

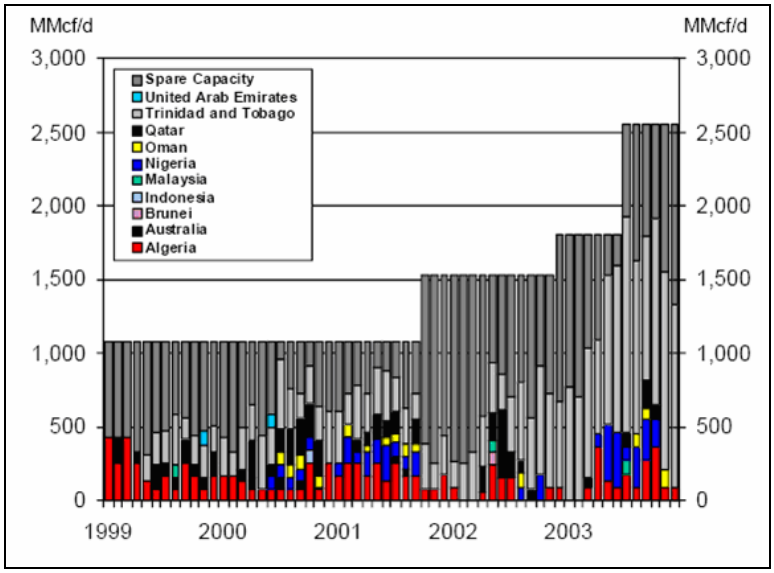
The U.S. imported a record amount of LNG in 2003, 507 Bcf, an increase of 121% over 2002. The sources of supply for this LNG are of interest and the quantities and sources are shown in the Figure 3.9.5.

Figure 3.9.4 – Production Change and Gas Wells Drilled on the Western Canadian Sedimentary Basin



Sources: StatsCan, CAPP, Daily Oil Bulletin, reproduced in NRCan

Figure 3.9.5 – U.S. LNG Imports



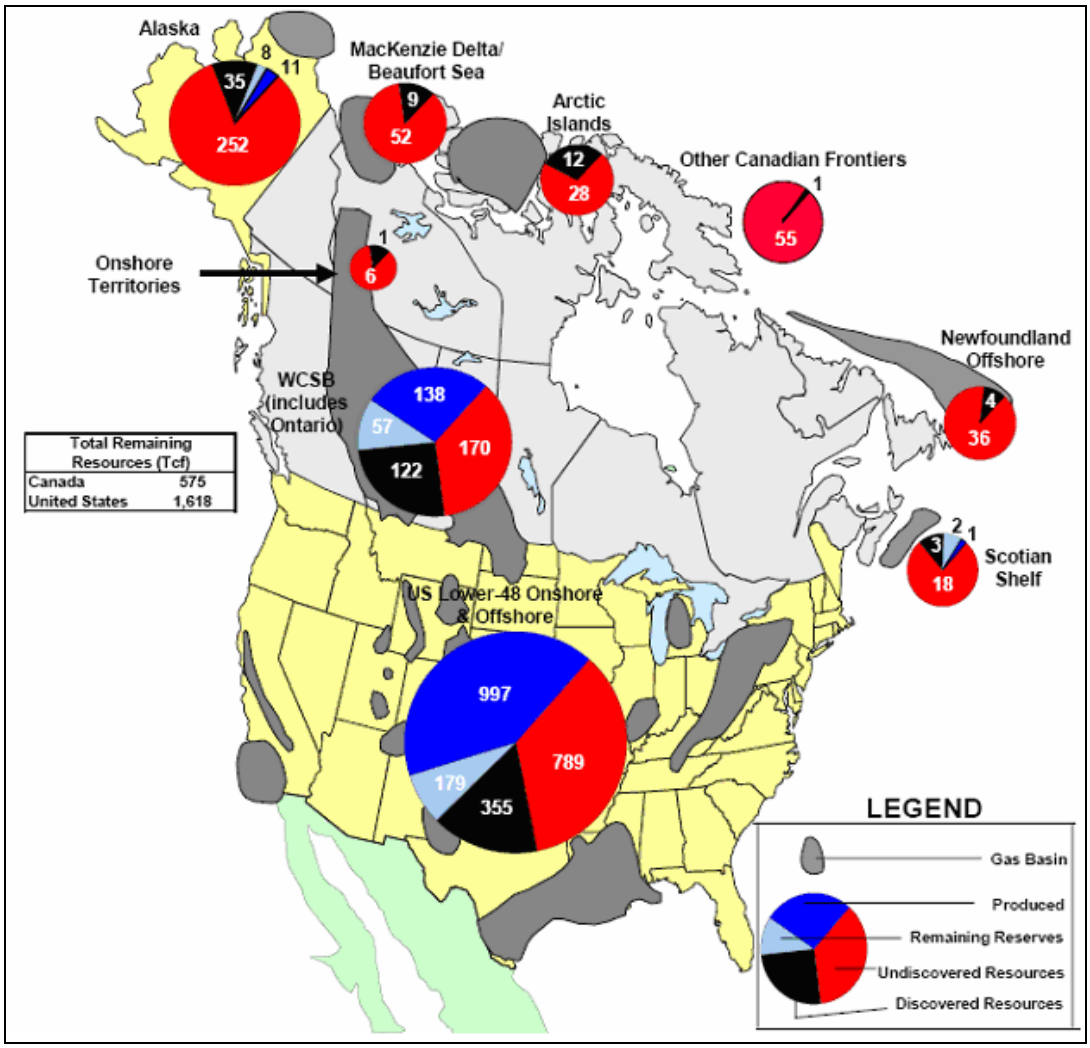
Sources: EIA, Company Website, reproduced in NRCan

Imports from Trinidad and Tobago represented 75% of all U.S. LNG imports in 2003. These were followed in significance by Algeria (11%) and Nigeria (10%).

At the end of 2004 there were 8 LNG import terminals being proposed for Canadian sites, totalling 4.91 Bcf/d in send-out capacity. The start dates for these terminals range from 2007 to 2009, but only two had received provincial-federal environmental approval as of August 2004.

North American natural gas resources and reserves, as known in 2004, are portrayed in the following figure and table.

Figure 3.9.6 – Canadian and U.S. Natural Gas Resources and Reserves (Tcf)



Sources: NEB, EIA, MMS, USGS, reproduced in NRCan

Table 3.9.4 – North American Gas Reserves and Resources

(Tcf)	Proved Reserves (Jan.1/03)	Discovered Resources 2	Undiscovered Resources	Total Remaining Resources
Alberta	45	101	61	207
British Columbia	9	14	27	50
Saskatchewan	3	5	1	9
Mainland Territories	0	1	6	7
Unconventional Resources[3]	0	0	80	80
Total Western Canada	**57**	**121**	**175**	**353**
Ontario	0	1	1	2
Nova Scotia	2	3	18	23
Total Eastern Canada	**2**	**4**	**19**	**25**
Grand Banks and Labrador	0	4	36	40
Mackenzie/Beaufort	0	9	52	61
Arctic Islands	0	12	28	40
Other Frontier	0	1	55	56
Total Frontier	**0**	**26**	**171**	**197**
Total Canada[4]	**59**	**151**	**365**	**575**
U.S. Onshore and State Offshore	144	322	320	785
U.S. Federal Offshore	25	68	362	455
Unconventional Resources[3]	18	0	359	377
Total U.S.	**187**	**390**	**1,041**	**1,618**
Total North America	**246**	**541**	**1,406**	**2,193**

Sources: NEB, CAPP, EIA, USGS, MMS. Notes: 1 Resource estimates are as of the latest estimates generated by the NEB, CAPP, USGS and MMS. They were not necessarily generated in the current year, nor at the same time. (2) Discovered resources excludes reserves (3) Unconventional gas is comprised of coalbed methane, shale gas, and tight gas. (4) Canadian reserves data is from CAPP. All other Canadian resource numbers are from the NEB's "Canada's Conventional Natural Gas Resources" (April 2004) and the NEB's "Canada's Energy Future: Scenarios for Supply and Demand to 2025" (July 2003).

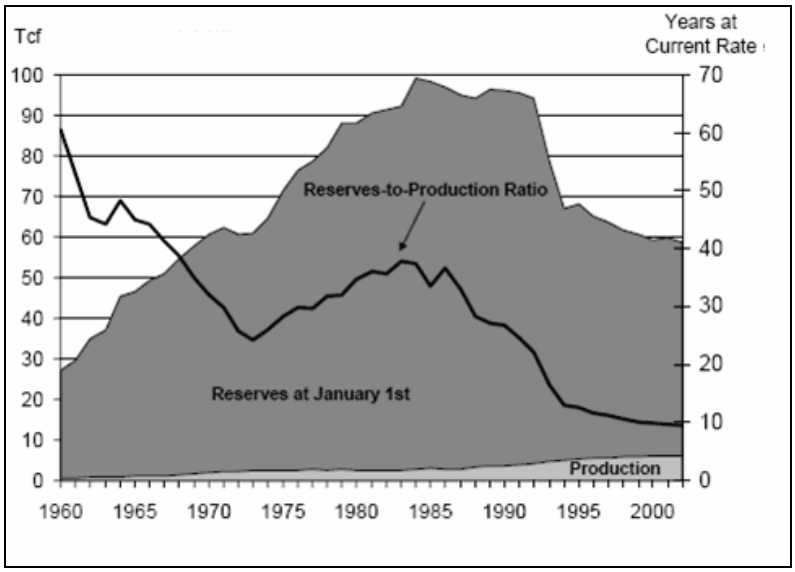
The National Energy Board's most current (1994) estimate for ultimate potential of conventional natural gas in Canada, including proved reserves, is 495 Tcf. In addition, it also estimates that another 80 Tcf of undiscovered, unconventional (coalbed methane, tight gas and shale gas) natural gas resources exist in the WCSB, providing a total of 575 Tcf Canadian reserve. At 2002 levels of production, Canada has about a 77 year supply of natural gas.

Estimates of the U.S. natural gas resource base, including proved reserves are 1,618 Tcf. At 2002 levels of domestic production, the U.S. has about an 85 year supply of natural gas.

One difficulty with these apparently comforting numbers is that Canada already has to import gas, and the basis for the numbers is "2002 production" not consumption, which is higher than production now and growing. The key to how many years of supply are available in North America rests heavily on what is done to adjust consumption rates.

Figure 3.9.7 compares proved Canadian gas reserves and production, illustrating the maturity of Canadian gas supplies.[3]

Figure 3.9.7 – Canadian Gas Reserves and Production



Sources: NEB, StatsCan, CAPP, reproduced in NRCan

Canadian reserves peaked in 1983, and then fell very quickly in 1994 because of removal of old reserves that had been on the books for some time. The rate of decrease of reserves has slowed and the Canadian Reserves-to-Production ratio is now at 9.78, similar to that in the U.S.

3.9.3.2 Recent Gas Prices

Figure 3.9.8 shows the Canadian and U.S. natural gas prices in 2003.

The lowest prices are typically at the well head, with increasing prices to reflect the significant pipeline costs for delivery, as the hub is more remote from the well-head.

The map shows natural gas spot (monthly) market prices for 2003. Prices shown are the annual average of 12 months, except for prices at the export border points, which are volume-weighted average prices.

[3] [3] The reserves are shown in dark shading; production is the light shading at the bottom of the graph. The radio of the two is the dark line.

Figure 3.9.8 – Canadian and U.S. Gas Prices in 2003

Sources: GLJ, NEB, reproduced in NRCan

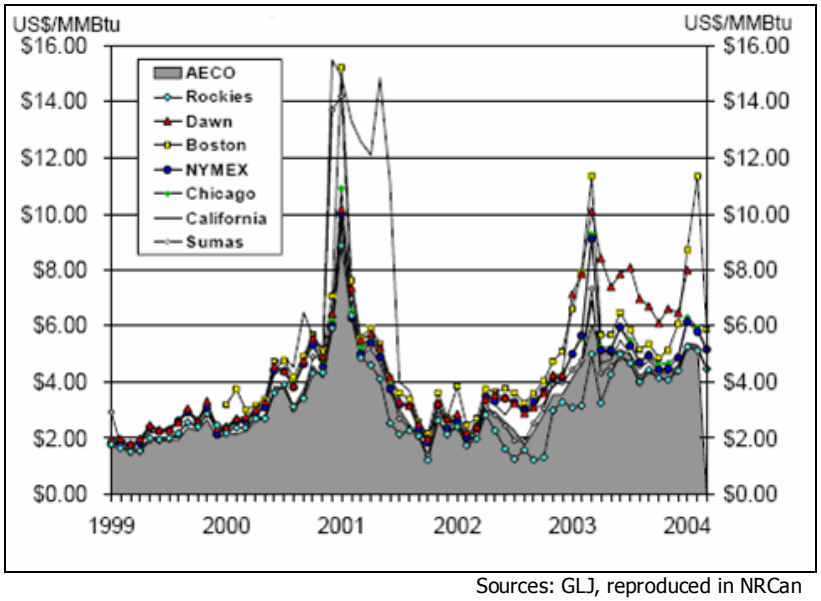
Table 3.9.5 shows the regional natural gas prices, 2003 vs. 2002.

Table 3.9.5 – Regional Natural Gas Prices

Region	2003 Avg. ($U.S./MMBtu)	2002 Avg. ($U.S./MMBtu)	Change 03 vs 02	% Change 03 vs 02
AECO-C (Southern Alberta)	$4.75	$2.58	$2.17	84%
NYMEX (Louisiana)	$5.39	$3.22	$2.16	67%
Kern County (California)	$4.49	$2.97	$1.52	51%
Huntingdon/Sumas (B.C.)	$4.66	$3.99	$0.67	17%
Opal (Rockies)	$4.13	$2.04	$2.09	102%
Chicago	$5.46	$3.25	$2.21	68%
Boston	$6.35	$3.71	$2.64	71%
Dawn (Ontario)	$5.62	$4.85	$0.76	16%

Source: GLJ reproduced in NRCan

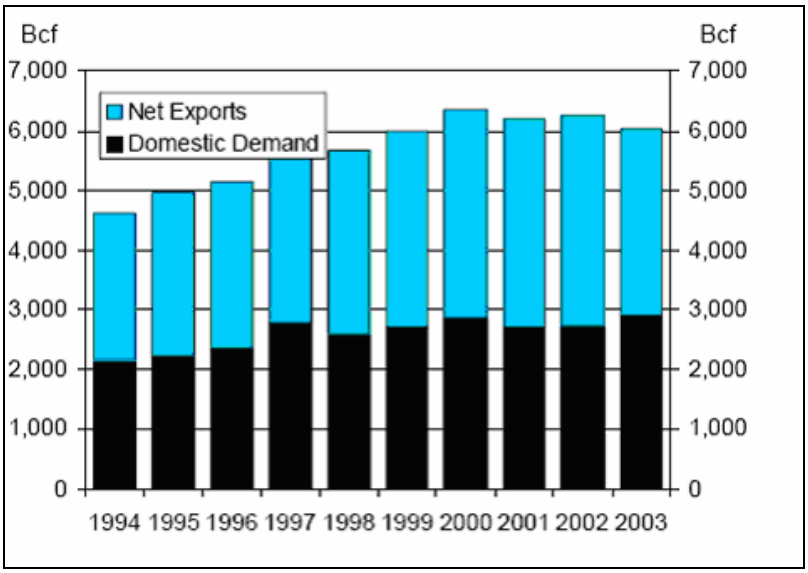
Figure 3.9.9 – Regional Natural Gas Prices



Sources: GLJ, reproduced in NRCan

Exports now constitute a major part of Canada's total gas production as in Figure 3.9.10.

Figure 3.9.10 – Domestic Demand and Net Exports



Sources: StatsCan, NEB, NRCan estimates

Shrinking Canadian production is leading to decreased exports and increased imports. In 2003, exports were 58% of total Canadian gas sold, and 15% of U.S. natural gas consumption. Natural gas imports into Canada, primarily through the Courtwright import point in southern Ontario near the Dawn trading hub, have been climbing steadily. Imports were 43% higher in 2003 than in 2002 and 650% higher than in 1999.

Prices for exported gas for the years 2002 to 2004 are shown below.

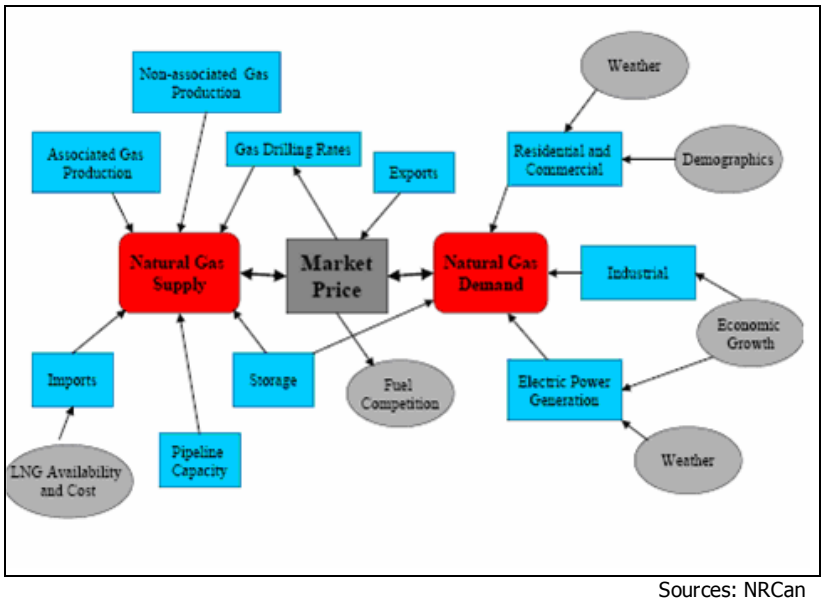
Table 3.9.6 – Domestic and International Border Export Prices

International Border Export Prices						U.S. Prices	Canadian Markets			
Year	**Month**	**West $US/ MMBtu**	**MW $US/ MMBtu**	**NE $US/ MMBtu**	**Average $US/ MMBtu**	**NYMEX $US/ MMBtu**	**AECO $Cdn/GJ**	**AECO $US/ MMBtu**	**Huntingdon $US/ MMBtu**	**Westcoast St 2 $US/MMBtu**
2002		**$2.72**	**$3.13**	**$3.49**	**$3.07**	**$3.22**	**$3.83**	**$2.57**	**$2.68**	**$2.56**
2003	January	$4.33	$4.72	$5.38	$4.81	$4.99	$6.04	$4.13	$4.44	$4.16
	February	$4.62	$5.39	$6.14	$5.38	$5.66	$6.71	$4.68	$4.76	$4.55
	March	$6.46	$7.95	$7.74	$7.38	$9.11	$8.45	$6.04	$7.32	$7.90
	April	$4.54	$5.04	$5.22	$4.94	$5.14	$7.20	$5.21	$4.29	$4.22
	May	$4.73	$5.04	$5.21	$4.99	$5.12	$6.48	$4.94	$4.58	$4.41
	June	$5.05	$5.53	$5.73	$5.44	$5.95	$6.63	$5.17	$4.87	$4.67
	July	$4.77	$5.11	$5.42	$5.10	$5.30	$6.50	$4.96	$4.65	$4.45
	August	$4.39	$4.60	$4.90	$4.63	$4.69	$5.58	$4.22	$3.93	$3.73
	September	$4.53	$4.65	$4.97	$4.72	$4.93	$5.77	$4.46	$4.36	$4.17
	October	$4.22	$4.39	$4.70	$4.44	$4.44	$5.47	$4.37	$4.14	$3.94
	November	$4.24	$4.25	$4.75	$4.41	$4.45	$5.59	$4.49	$4.08	$3.87
	December	$4.51	$4.94	$5.39	$4.95	$4.86	$5.32	$4.28	$4.50	$4.29
2004	January	$5.21	$5.82	$6.71	$5.91	$6.15	$6.58	$5.36	$5.20	$4.99
	February	$4.95	$5.47	$6.14	$5.52	$5.77	$6.70	$5.32	$5.20	$4.99
	March	$4.12	$4.40	$4.74	$4.42	$5.15	$5.93	$4.71	$4.42	$4.21
2004	Average (YTD)	**$4.76**	**$5.23**	**$5.86**	**$5.28**	**$5.69**	**$6.40**	**$5.13**	**$4.94**	**$4.73**
2003	Average (YTD)	**$5.14**	**$6.02**	**$6.42**	**$5.86**	**$6.59**	**$7.07**	**$4.95**	**$5.51**	**$5.54**
2003	Average	**$4.70**	**$5.13**	**$5.46**	**$5.10**	**$5.39**	**$6.31**	**$4.75**	**$4.66**	**$4.53**
2002 /03	% Change[1]	**73%**	**64%**	**57%**	**66%**	**67%**	**65%**	**85%**	**74%**	**77%**
2003 /04	% Change[2]	**-7%**	**-13%**	**-9%**	**-10%**	**-14%**	**-9%**	**4%**	**-10%**	**-15%**

Sources: GLJ, NEB, NRCan estimates Notes: (1) Annual percentage change of prices between the years 2002 and 2003. (2) Year-to-date percentage change of prices between the years 2003 and 2004 (January to March).

Natural gas prices are driven by supply/demand fundamentals as illustrated by Figure 3.9.11.

Figure 3.9.11 – Natural Gas Price Drivers



Sources: NRCan

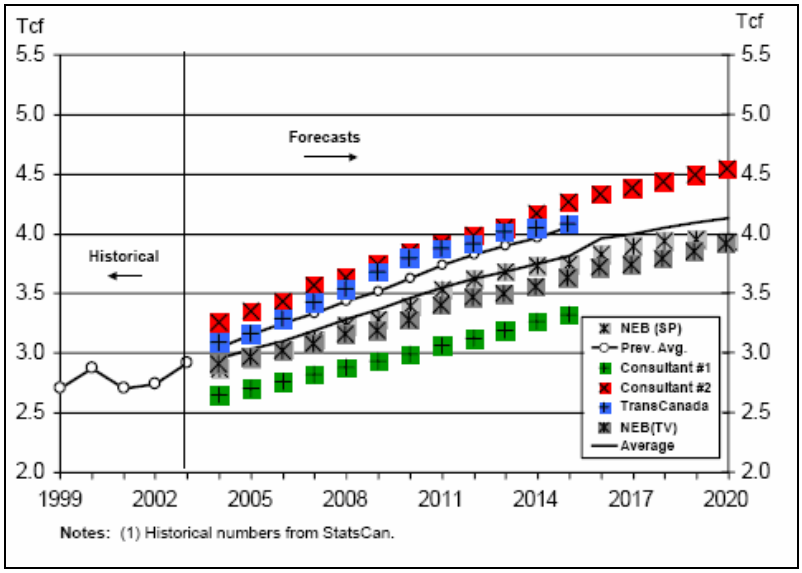
Demand is driven by weather, economic growth and fuel consumption. The supply side is affected by production, drilling rates, storage and available pipeline capacity.

3.9.4 Long-Term Forecasts – to 2020

In the U.S., the residential and commercial natural gas demand is forecast to remain relatively stable, growing at about 1%. The industrial and power generation sectors are expected to account for most of the demand growth in the U.S., increasing at 1.1% and 2.5% per year respectively.

In Canada there are a number of growth forecasts as shown below.

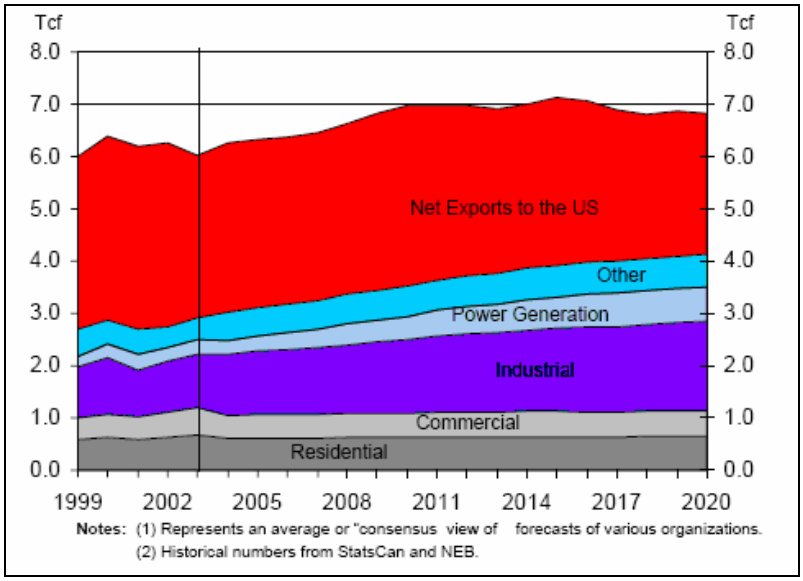
Figure 3.9.12 – Canadian Natural Gas Demand Forecasts



Sources:NEB, TransCanada and various consultants, reproduced in NRCan

The average of the forecasts shows Canadian gas demand at 4.1 Tcf by 2020, representing an average growth rate of about 2.1% per year over the forecast period. A breakdown of the total demand for Canadian natural gas by sector is given below.

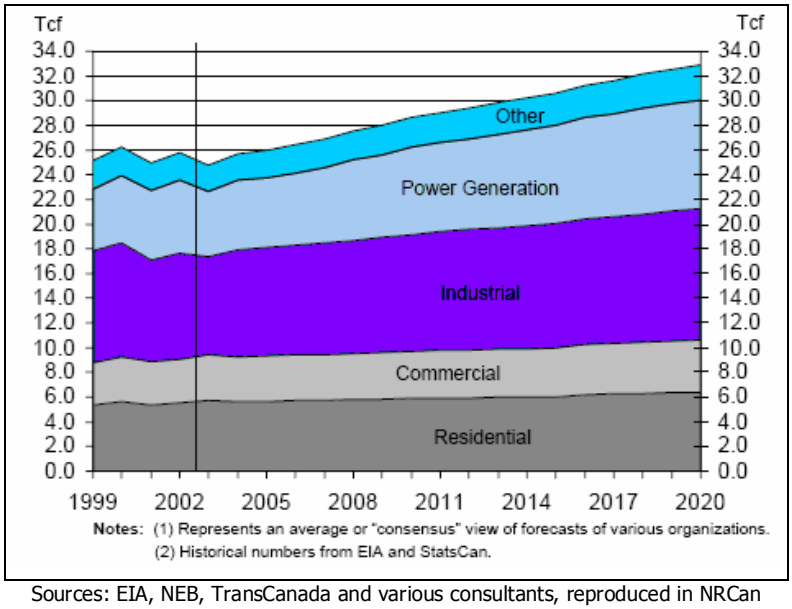
Figure 3.9.13 – Demand for Canadian Natural Gas



Sources: NEB, TransCanada and various consultants, reproduced in NRCan

Putting the Canadian and U.S. forecasts together provides the following information:

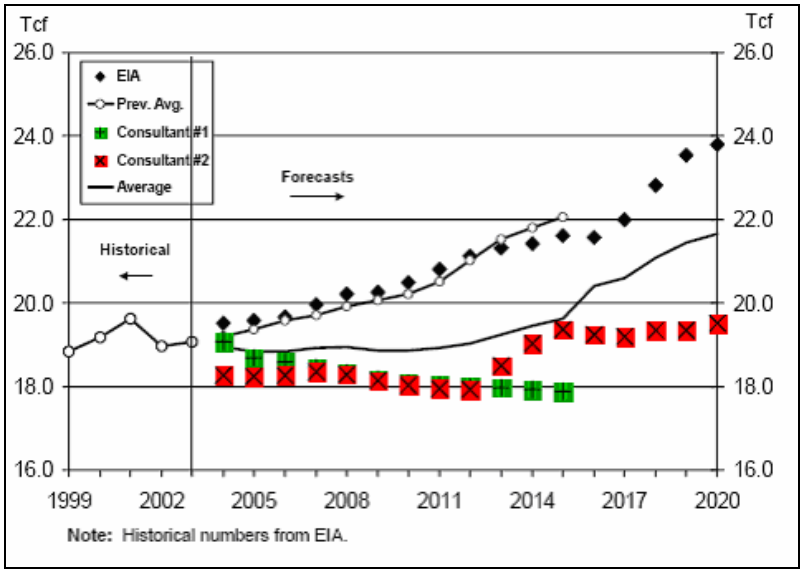
Figure 3.9.14 – North American Natural Gas Demand Growth



Sources: EIA, NEB, TransCanada and various consultants, reproduced in NRCan

This forecast implies that North America will need an additional 8.2 Tcf of annual gas supply by 2020. This brings us to the supply side information. The following figures provide insight into the forecasted supply both on a North American and Canadian basis.

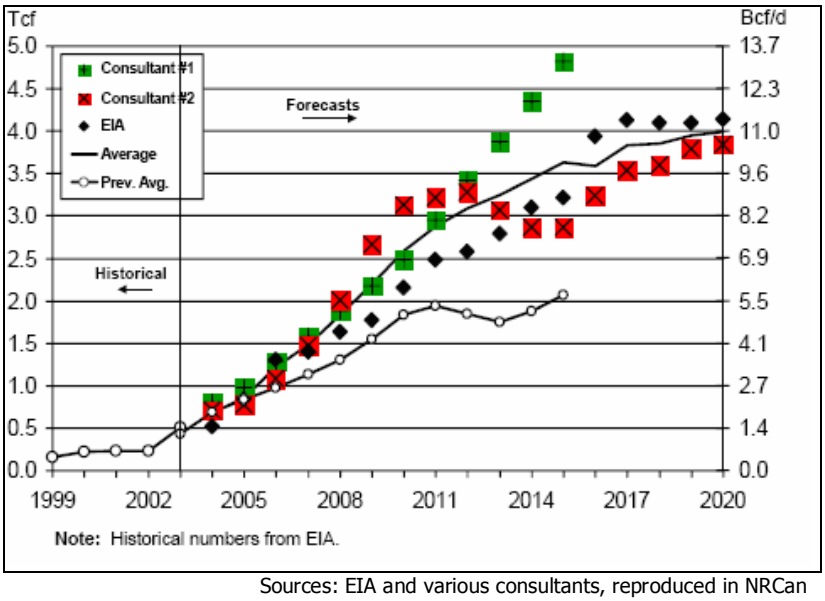
Figure 3.9.15 – U.S. Natural Gas Production Forecasts



Sources: EIA and various consultants, reproduced in NRCan

There are considerable differences in opinion about U.S. gas production. Some forecasts have gas from Alaska in the mix at some point over the forecast period.

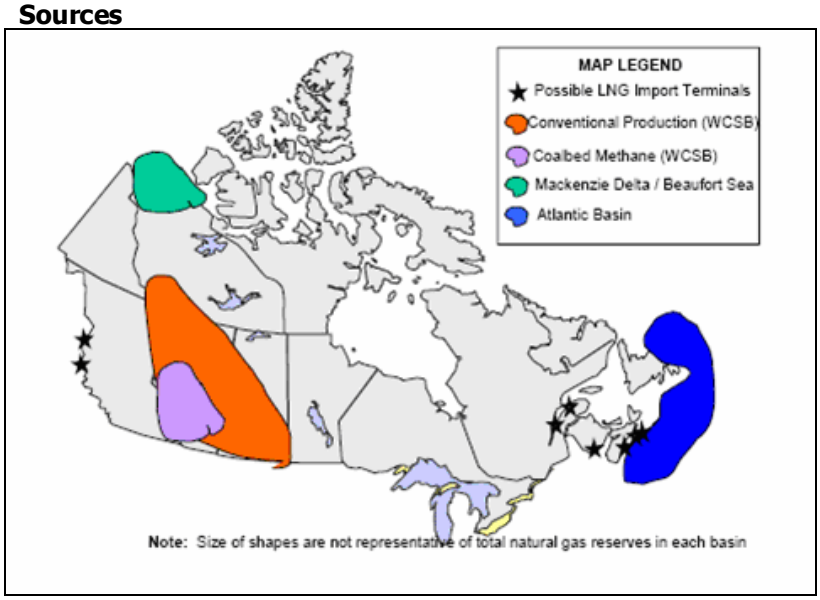
Figure 3.9.16 – U.S. LNG Supply Forecasts



Sources: EIA and various consultants, reproduced in NRCan

The average sees the U.S. LNG imports reaching 12% of the total North American gas supply by 2020.

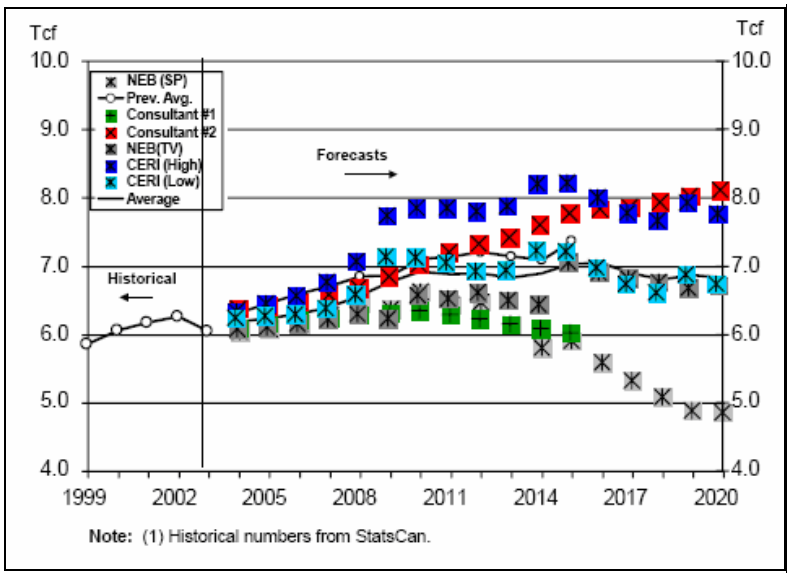
Figure 3.9.17 – Possible Canadian Incremental Natural Gas Sources


MAP LEGEND
Possible LNG Import Terminals
Conventional Production (WCSB)
Coalbed Methane (WCSB)
Mackenzie Delta / Beaufort Sea
Atlantic Basin
Note: Size of shapes are not representative of total natural gas reserves in each basin

Sources: NRCan

Additional sources of supply, beyond the conventional reservoirs and producing areas are not expected to become available in any significant quantity before 2007.

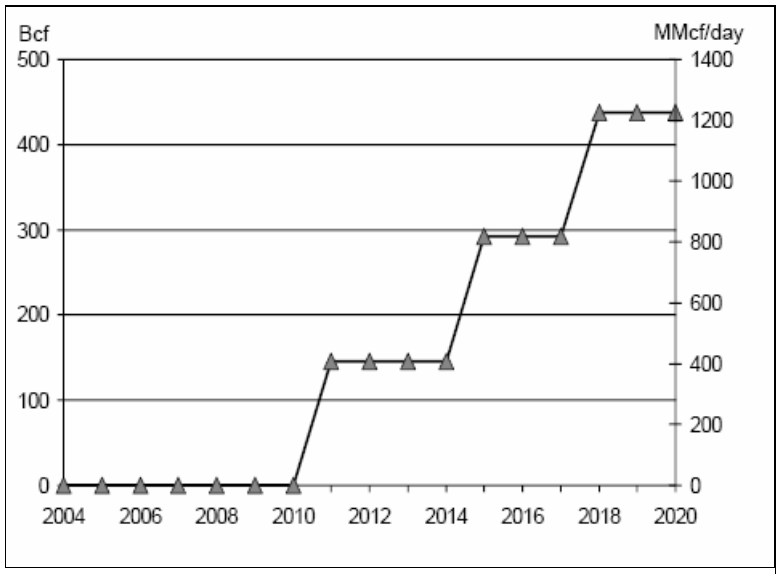
Figure 3.9.18 – Canadian Natural Gas Production Forecasts



Sources: NEB, CERI and various consultants, reproduced in NRCan

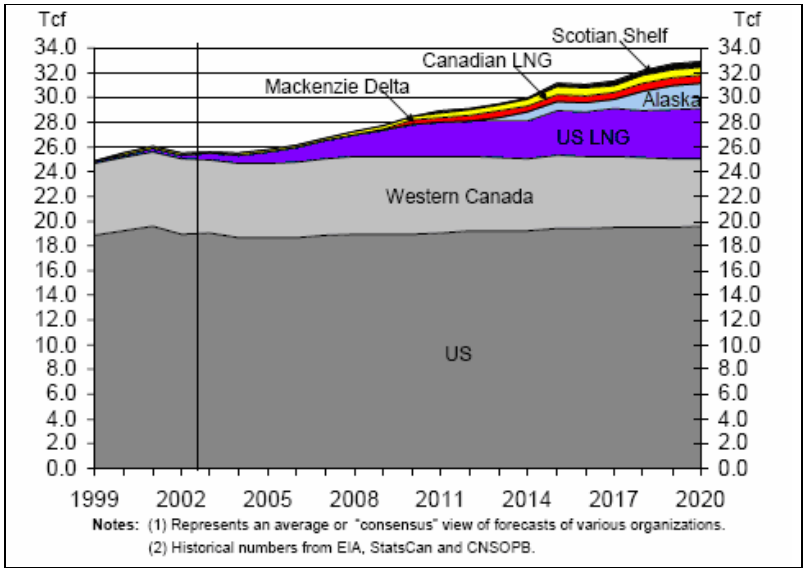
The average of the forecasts shows Canadian production at about 6.8 Tcf by 2020, and an average annual growth rate of 0.6%. This forecast is about 8% lower than one issued a year earlier, taking into account the maturing WCSB as well as uncertainties regarding natural gas reserves and supply in Atlantic Canada.

Figure 3.9.19 – Canadian LNG Supply Forecast



Sources: NEB, *Canada's Energy Future: Scenarios for Supply and Demand to 2025, July 2003*,reproduced in NRCan

Figure 3.9.20 – North American Natural Gas Supply Growth

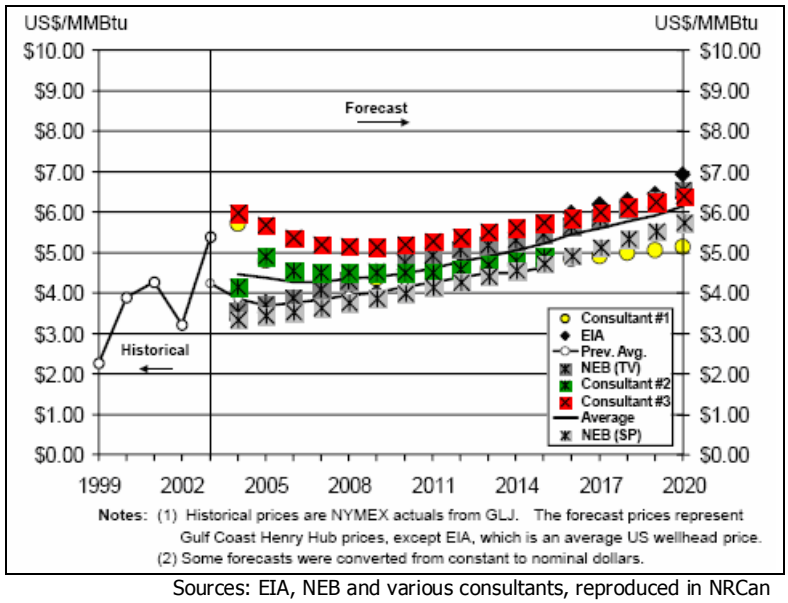


Sources: EIA, NEB, CERI, TransCanada and various consultants, reproduced in NRCan

Currently, Canada does not import any LNG. In order to import gas for Canadian needs, and also to enable additional gas exports to the United States, it will be necessary to build some LNG facilities. The NEB forecasts that Canadian LNG imports will equal 1.2 billion cubic feet per day, or 0.44 Tcf in 2020. A "consensus" view of the Canadian natural gas supply in 2020 forecasts LNG to be 6% of the total Canadian supply.

Price forecasts for the U.S. and Canada for Natural Gas Supplies are given in the following figures.

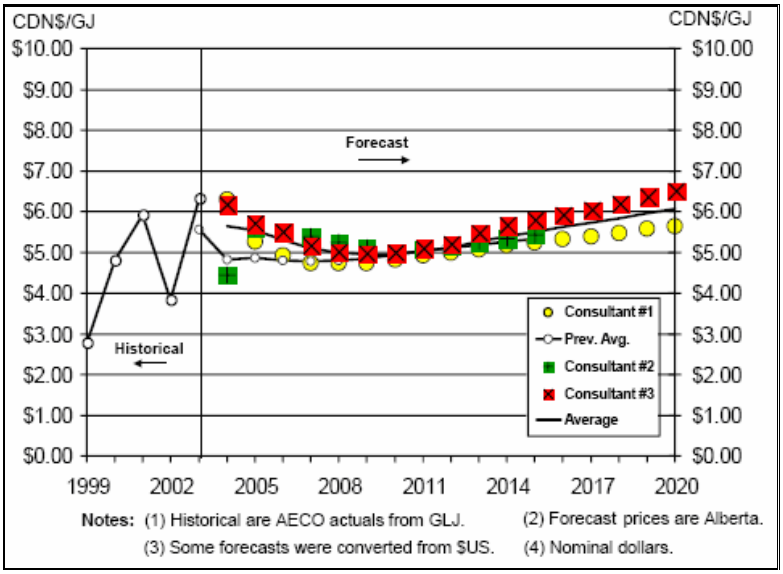
Figure 3.9.21 – U.S. Natural Gas Price Forecasts



Sources: EIA, NEB and various consultants, reproduced in NRCan

The average of the six forecasts shows that U.S. prices were expected to be less than 2003 levels in the short term, but closer to or more than 2003 levels over the latter half of the forecast period. These forecasts were reported in late 2004, before the substantial increase in price experienced during 2005.

Figure 3.9.22 – Canadian Natural Gas Price Forecasts

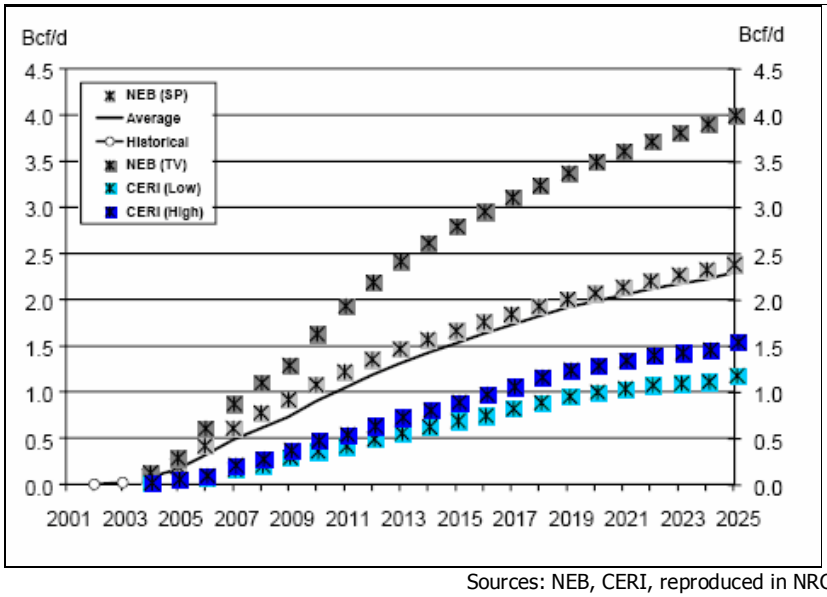


Sources: Various Consultants, reproduced in NRCan

Canadian prices were expected to average approximately $5.65/GJ and continue to hover between $5.00/GJ and $6.00 /GJ over the entire forecast period. The average forecast for 2015 and 2020 sees gas prices at $5.50 /GJ and $6.10 /GJ, respectively.

This forecast takes place in the context of the following forecast of export volumes, domestic sales and CBM production.

Figure 3.9.23 – Western Canada Coalbed Methane Production Forecast



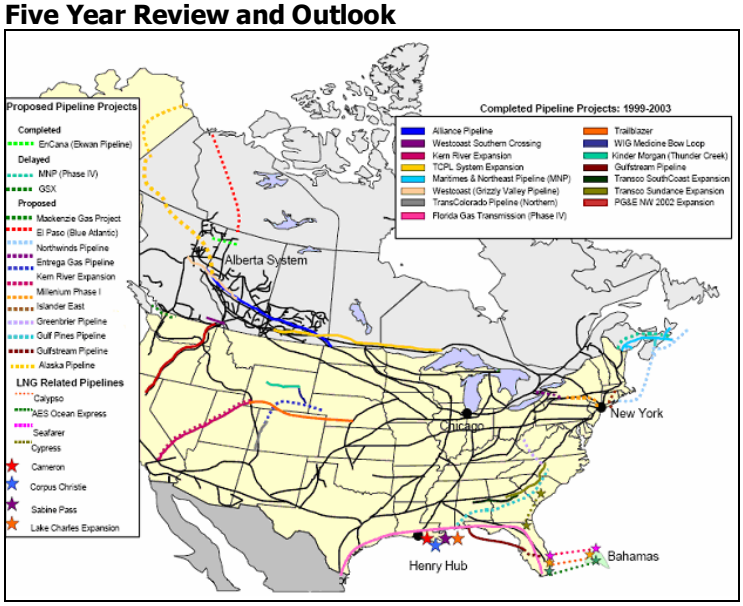
Sources: NEB, CERI, reproduced in NRCan

Table 3.9.7 – Export Volumes and Domestic Sales

(Bcf)	2000	2001	2002	2003	2004	2005	2010	2015	2020
Huntingdon (Westcoast)	356	324	335	304	-	-	-	-	-
Kingsgate (TCPL)	833	781	696	562	-	-	-	-	-
Total U.S. West	**1,189**	**1,105**	**1,031**	**866**	**-**	**-**	**-**	**-**	**-**
Monchy (TCPL)	784	744	768	763	-	-	-	-	-
Emerson (TCPL)	491	390	397	362	-	-	-	-	-
Elmore (Alliance)	73	526	568	567	-	-	-	-	-
Miscellaneous	30	31	37	24	-	-	-	-	-
Total U.S. Midwest	**1,378**	**1,691**	**1,770**	**1,716**	**-**	**-**	**-**	**-**	**-**
Iroquois (TCPL)	363	319	323	323	-	-	-	-	-
Niagara Falls (TCPL)	423	326	327	288	-	-	-	-	-
Chippawa (TCPL)	37	54	104	81	-	-	-	-	-
St. Stephen (MNP)	117	141	143	130	-	-	-	-	-
East Hereford (TCPL)	34	39	48	45	-	-	-	-	-
Cornwall (TCPL)	8	9	8	7	-	-	-	-	-
Napierville (TCPL)	19	33	19	19	-	-	-	-	-
Phillipsburg (TCPL)	8	6	7	6	-	-	-	-	-
Highwater (TCPL)	15	5	0	0	-	-	-	-	-
Total U.S. Northeast	**1,024**	**932**	**979**	**899**	**-**	**-**	**-**	**-**	**-**
Total Gross Exports	**3,591**	**3,728**	**3,780**	**3,481**	**3,541**	**3,515**	**3,762**	**3,517**	**2,997**
Total Canadian Demand	**2,872**	**2,697**	**2,736**	**2,914**	**2,950**	**3,026**	**3,457**	**3,809**	**4,128**
Imports to Canada[1]	**80**	**228**	**260**	**371**	**300**	**300**	**300**	**300**	**300**
Total Net Exports	**3,511**	**3,500**	**3,520**	**3,110**	**3,241**	**3,215**	**3,462**	**3,217**	**2,697**
Total Domestic Sales[2]	**2,792**	**2,469**	**2,476**	**2,543**	**2,650**	**2,726**	**3,157**	**3,509**	**3,828**
Total Sales[3]	**6,383**	**6,197**	**6,256**	**6,024**	**6,191**	**6,241**	**6,919**	**7,027**	**6,825**

Sources: NEB, StatsCan, TransCanada, CERI, and various consultants. Notes: (1) Imports are assumed to equal 300 Bcf per year over the forecast period. (2) Domestic sales equal to Canadian demand less imports. (3) Total sales equals gross exports plus domestic sales.

Figure 3.9.24 – North American Natural Gas Pipelines: Five Year Review and Outlook

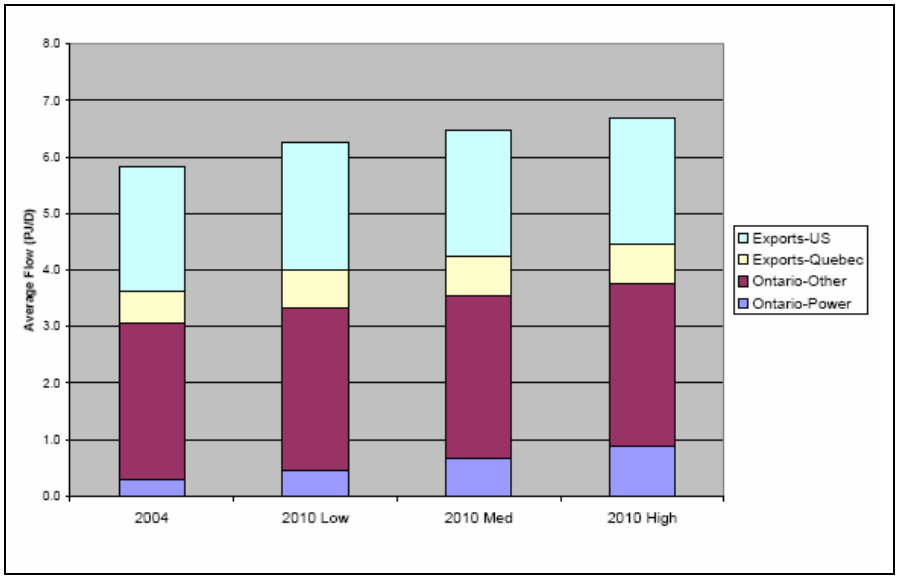


Sources: Pipeline Companies, industry press and various consultants, NRCan

3.9.5 Additional Information from the Ontario Energy Board's Natural Gas Electricity Interface Review

The following figure shows the total average daily gas flows into and across Ontario.

Figure 3.9.25 – Total Average Daily Flows Into and Across Ontario

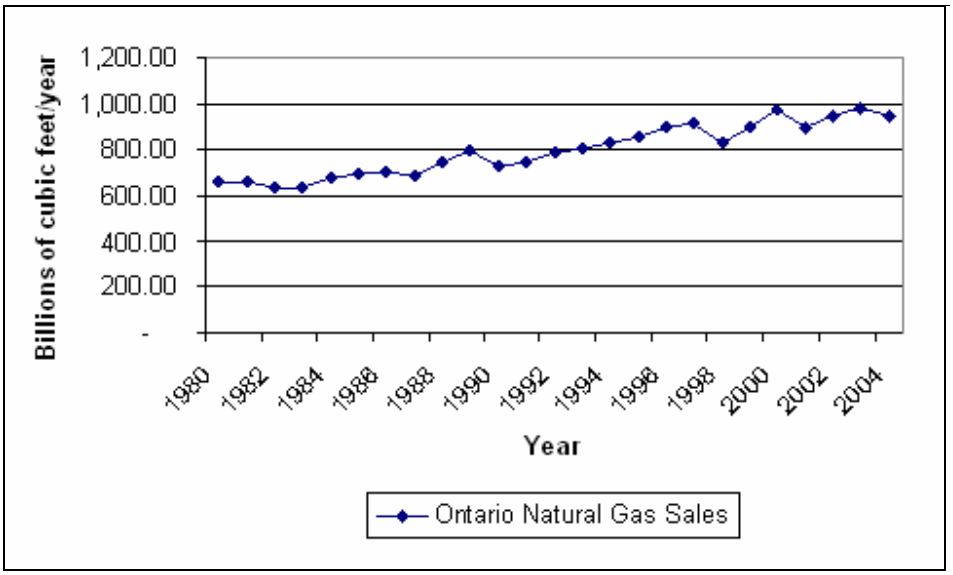


Source: Natural Gas Electricity Interface Review

This provides a picture of the recent and projected near-term flows expected, including the tripling of gas used for generating electricity between 2004 and 2010.

Another element of context for the material that follows is the following figure that shows the sales of natural gas in Ontario going back to 1980.

Figure 3.9.26 – Ontario Natural Gas Sales



Source: Canadian Gas Association, National Energy Board, Statistics Canada

Ontario is one of Canada's largest markets for natural gas, almost 1,000 Petajoules (PJ) annually, with a peak demand around 3PJ per day. More than 95% of the gas consumed in Ontario comes from outside the province, mostly from the WCSB, mainly through the TransCanada Pipelines Limited (TCPL) system and or the Vector Pipeline route (see Figure 3.9.27 below.).

As Figure 3.9.27 shows, the gas market is served by several routes. TCPL's northern route provides delivery to Ontario from the WCSB. TCPL's pipeline splits at North Bay Junction. About 2.2 PJ/d (of capacity) flows from the junction along the eastern leg to Ottawa and Montreal, and also to the eastern export points at Iroquois Waddington, TransQuébec and Maritimes (TQM), and Portland Natural Gas Transmission system.

On November 21, 2005, the staff of the Ontario Energy Board (OEB) issued a report "Natural Gas Electricity Interface Review" (NGEIR). It reviews the issues that are arising out of the increasing amounts of gas-fired generation planned for Ontario, partly to deal with increased electricity load and aging generation, but largely to deal with new generation required to allow coal-fired generation to be replaced by 2009.

The amounts of additional gas required are significant and new delivery and storage facilities will be required to accommodate the new demand. The number of parameters involved and

the possible range of the parameters is part of the problem that needs addressing. However, the costs of the additional facilities and who is required to pay for them has also become an issue. The increased demand is expected to raise commodity prices because of pressure on the demand/supply ratio. This is likely to affect both generation and non-generation users. In addition, a subject of much debate is the matter of who pays for additional pipeline and storage capacity that is required to meet the additional gas loads imposed by the generators.

This section will deal briefly with the subject matter as an issue that could affect gas prices in Ontario mainly, but likely elsewhere. It is not possible at this time to determine the actual effects on unit costs for gas, as the gas volumes, pipelines, storages and other facilities can only be determined when the specifics are known better.

The NGEIR report notes that in the event that all current coal-fired generation is replaced with gas-fired power generation, gas-fired generators would become the largest class of gas consumers in the province – using more than all natural gas residential customers combined. It also notes that the gas demands of gas-fired generation are not likely to be the fairly steady load profile of other users, and hence there will be demands on the delivery systems that have not been present before.

These two observations and analyses that follow show that "there will be significant gas infrastructure investment needed in Ontario that could cost from $245 million to $815 million, depending on the increase in gas-fired generation, the location of these generators and their gas storage and deliverability requirements". The range of possibilities assessed is shown in the following table which is taken from the NGEIR report, as are all the figures shown in this section not labelled otherwise.

Table 3.9.8 – Total Facilities Cost Estimates ($ Million)

	Low Scenario (4,305 MW)		Medium Scenario (5,265 MW)		High Scenario (6,775 MW)	
	Low	**High**	**Low**	**High**	**Low**	**High**
Dawn to Parkway	75	115	110	170	145	230
Storage (Space and Deliverability)	40	240	55	255	90	270
Laterals/Reg/Meters	130	225	150	250	205	315
Total Ontario Only	245	580	315	675	440	815
Upstream	30	60	210	255	460	560
TOTAL	275	640	525	930	900	1,375

Notes: (1) Preliminary high level estimates. Costs could vary significantly due to: plant location, lead times, land acquisition, highway crossings and ROWs. (2) Assumes in the high case 3725 MW served east of Dawn and 3050 MW in the Northwest and cogeneration sourced via TCPL or west of Dawn. (3) Assumed LNG on St. Lawrence in the medium and high scenarios as of 2010. Source: OEB

A second phase examined how the costs of additional infrastructure and services are considered in the regulatory process and whether changes are needed. It concluded that there was no need for a fundamentally different regulatory approach to deal with the gas-fired generation growth. It also concluded that the OEB should consider whether new services that would meet their

unique demand characteristics should be offered as a tariff item to gas-fired generators and other qualifying customers.

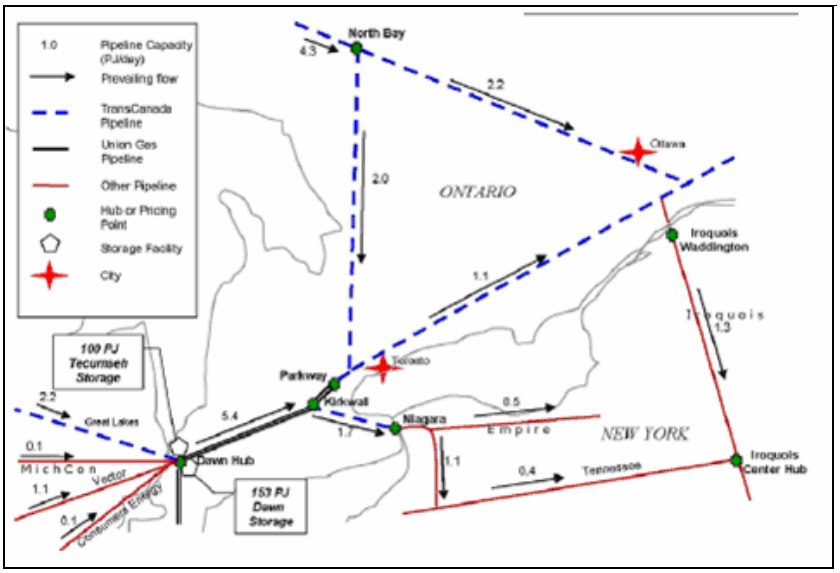
The primary drivers for the concerns covered in the review are:

- The need for additional gas storage capacity in Southern Ontario close to the new gas-fired generation to meet the sudden changes in generation rate that are part of operating in the electricity market.
- The need for additional upstream gas transmission pipeline and other capacity improvements for the same reason.
- The need for additional flexibility in the operation of the gas delivery system so that gas deliveries can be rapidly shifted from one end-user to another without long delays.

The first two of these entail major costs and development times.

A map of the upstream delivery systems was included in the review and is shown below for information.

Figure 3.9.27 – Ontario Gas System Schematic



Sources: OEB

The noteworthy parts of this diagram are the location and size of the gas storages near Sarnia, Dawn and Tecumseh, and the gas delivery systems between there and the various locations around the Golden Horseshoe that are likely to contain the most dense applications of new gas-fired generation, although other delivery paths may also be affected. In short, new storage capacity will be required to smooth the delivery of gas from outside the province and make it available in rapidly changing amounts to meet the demands of generators. Additional gas transmission is required between the storages and the generators to provide for the same demands.

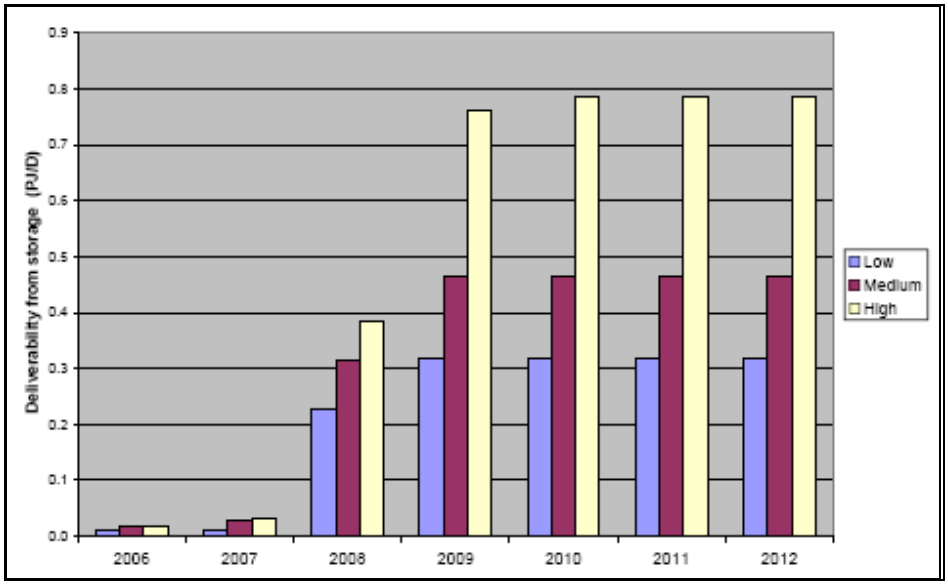
Dawn, in southwestern Ontario, is the meeting point for several major pipelines. It has become a leading market area hub, attracting Midwest and northeast shippers as well as providing service to Ontario shippers and the gas utilities in Ontario and Quebec. Through its Great Lakes Gas Transmission system, which delivers gas to the Dawn Hub, TCPL has another 2.2 PJ/d of capacity into Ontario. TCPL contracts on the Union system for capacity from Dawn to interconnections at Kirkwall and Parkway, near the western end of Lake Ontario.

Vector provides about 1 PJ/d of capacity into Ontario, also through the Dawn Hub. Vector provides access to a number of United States pipeline systems as well as storage facilities in Michigan. Vector interconnects with Alliance Pipelines in the Chicago area. The Chicago area is also a market area hub, providing access to numerous pipelines. Vector recently announced plans to increase its capacity to about 1.3 PJ/d, an increase of about 0.3 PJ/d, by the fall of 2007, and to 1.5 PJ/d by 2010.

Union has interconnections with Panhandle Pipelines near Windsor with a capacity of about 0.2 PJ/d. There are additional smaller inter-ties near Sarnia (Bluewater, St. Clair and Link pipelines) providing about 0.4 PJ/d of capacity.

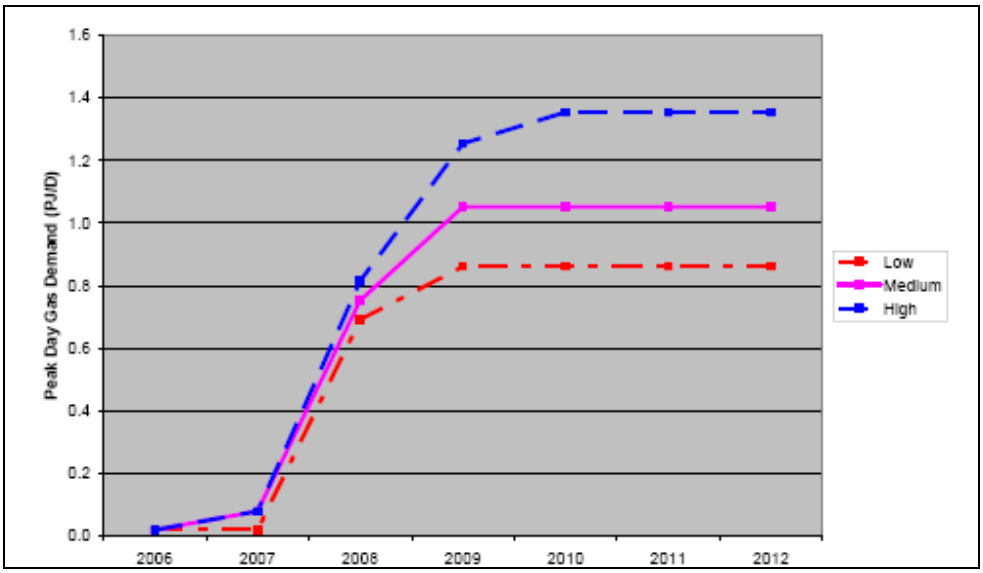
The potential demands of the generators can be seen in the two following figures.

Figure 3.9.28 – Storage Deliverability Demand for New Gas-Fired Generation*



Sources: OEB (NGEIR); * (assumes 5% deliverability)

Figure 3.9.29 – Peak Day Requirements for Gas-Fired Generators



Sources: OEB (NGEIR)

Upstream pipeline capacity is needed to deliver gas from the production basin or from a liquid hub to Ontario. Generators usually contract for a smaller amount of capacity than their average day requirements, which allows for variation in annual gas needs.

Marketers can also provide upstream capacity to generators.

Actual upstream pipeline capacity to meet the new needs would depend on the entry point of gas into Ontario (the gas supply source) and the in-Ontario delivery point for new generation. It also depends on the extent to which the gas requirements of additional supply are interruptible. Interruptible supply does not require guaranteed capacity. It is likely that new gas-fired generation will require a firm upstream supply and firm storage deliverability.

The specific details of the possible alternatives, their requirements and solutions are set forth in the OEB publication "Natural Gas Electricity Interface Review".

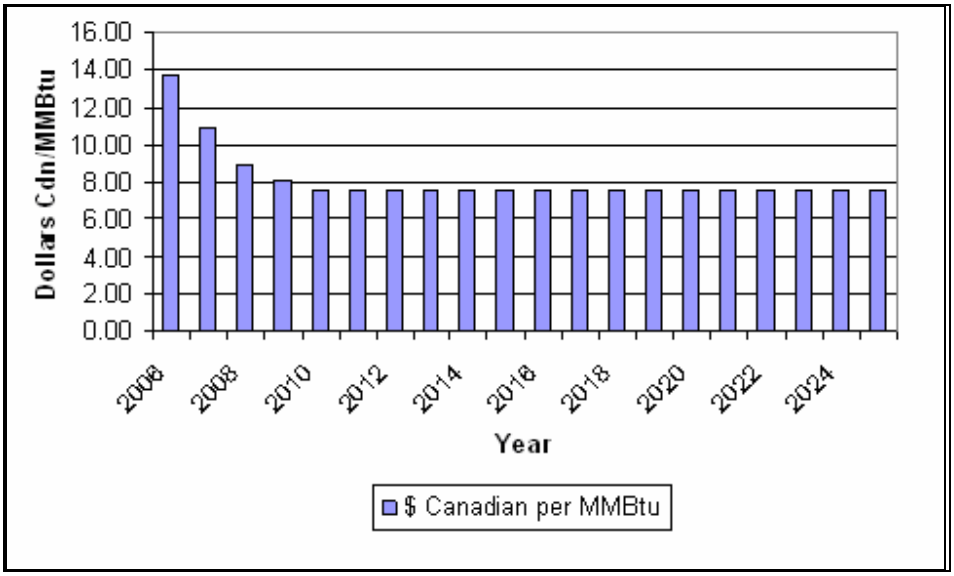
As was noted above, a forecast of the price increase of gas above the price otherwise forecast is not possible until the amounts, location and operating pattern of gas-fired generation are known. The effects on gas prices at Dawn, which will likely rise if the gas usage rate increases rapidly, are similarly unknown at this time.

What is clear is that the increased usage will put upward pressure on gas prices and that the delivery costs will increase for the generators and possibly also other natural gas customers.

Gas Price forecast Used in the Supply Mix Advice

OPA selected a gas price forecast for the analysis of supply options and portfolios on the basis of the industry technical fundamentals reviews in this section, supplemented by new information. Specifically, OPA used the Sproule forecast[4], which is seen to be close to $8/MMBtu over the period to 2020 as shown in Figure 3.9.30.

Figure 3.9.30 – Natural Gas Price Forecast for OPA Mix Study



Source: OPA

[4] See http://www.sproule.com/prices/downloads/October_31_2005_95.xls.

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